Air Quality Permit

Issued to:	CHS Inc. Laurel Refinery P.O. Box 909 Laurel, MT 59044-0909	Permit #1821-10 Application Complete: 08/22/03 Preliminary Determination Issued: 09/10/03 Department's Decision Issued: 09/30/03 Permit Final: 10/16/03 AFS #: 111-0012

An air quality permit, with conditions, is hereby granted to CHS Inc. Laurel Refinery pursuant to Sections 75-2-204 and 211, Montana Code Annotated (MCA), as amended, and the Administrative Rules of Montana (ARM) 17.8.740, *et seq*., as amended, for the following:

Section I: Permitted Facilities

A. Plant Location/Description

CHS Inc. operates a petroleum refinery located in the South ½ of Section 16, Township 2 South, Range 24 East, in Yellowstone County, Montana. The facility includes, but is not limited to, the following permitted equipment:

1. A hydrodesulfurization (HDS) complex to desulfurize fluidized catalytic cracking unit feedstocks operated and controlled by CHS Inc. A sulfur recovery unit (SRU) and tail gas treatment unit (TGTU) shall together utilize up to 70.7 long tons per day of equivalent sulfur obtained from the equipment installations to manufacture elemental sulfur.

   The general associated processes for the HDS complex at the CHS Inc. Laurel Refinery are listed below:

   a. Hydrogen Plant Reformer Heater (H-101), 175-foot stack

   b. Gas-Oil HDS Unit

      i. Reactor Charge Heater (H-201), 100-foot stack
      ii. Fractionator Feed Heater (H-202), 100-foot stack
      iii. Compressor Gas Engine (C-201B), 93.5-foot stack

   c. Amine Unit

   d. Sour Water Stripper (SWS) Unit

   e. SRU (Claus)

      i. Sulfur Reaction Furnace
      ii. Waste Heat Boiler
      iii. Reheater Furnace (E-407)
      iv. SRU Incinerator (INC-401), 150-foot stack

   f. TGTU

2. Boiler #10 - Natural gas/Refinery fuel gas fired, 99.9 MMBtu/hr.

3. Product Loading Rack and Vapor Combustion Unit - The product loading rack is used to transfer refinery products from tank storage to trucks, which transport the gasoline, diesel, or burner fuels to retail outlets.

4. No. 1 Crude Unit

5. Ultra Low Sulfur Diesel (ULSD) Unit and Hydrogen Plant

6. TGTU for Zone A's SRU #1 and SRU #2 trains

7. The CHS Inc. facility as a whole (as it relates to Plant-wide Applicability Limits (PALs)). The refinery flare is not included.

B. Current Permit Action

On July 30, 2003, the Department of Environmental Quality (Department) received a Montana Air Quality Permit Application from CHS Inc. to modify Permit #1821-09. The application was complete with the addition of modeling information provided to the Department on August 22, 2003. CHS Inc. requested to add a new TGTU and associated equipment for Zone A's SRU #1 and SRU #2 trains to control and reduce SO_2 emissions from this source. CHS Inc. submitted modeling to the Department for a determination of a minimum stack height for the existing SRU #1 and SRU #2 tail gas incinerator stack. CHS Inc. also submitted a letter to the Department to change the name on the permit from Cenex Harvest States Cooperatives to CHS Inc. The current permit action adds the new TGTU, sets a minimum stack height for the tail gas incinerator stack, and changes the name on the permit from Cenex Harvest States Cooperatives to CHS Inc.

Section II: Limitations and Conditions for the HDS Complex

A. CHS Inc. shall comply with all applicable standards and limitations, and the monitoring, recordkeeping and reporting requirements contained in 40 CFR Part 60, Standards of Performance for New Stationary Sources (NSPS). The following subparts, at a minimum, are applicable:

1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.

2. Subpart J - Standards of Performance for Petroleum Refineries applies to the SRU Incinerator Stack (E-407 & INC-401), the Fractionator Feed Heater Stack (H-202), the Reactor Charge Heater Stack (H-201), and the Reformer Heater Stack (H-101).

3. Subpart GGG - Standards of Performance for Equipment leaks of volatile organic compounds (VOC) in Petroleum Refineries applies to the HDS unit.

4. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems applies to the HDS unit.

B. CHS Inc. shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes. This applies to the sources in the HDS complex (ARM 17.8.304 (2)).

C. Limitations on Individual Sources

1. Old SWS

a. Sulfur dioxide (SO_2) emissions attributed to the old SWS shall not exceed 290.9 tons per year based on a rolling 12-calendar month total.

b. Nitrogen oxide (NO_x) emissions attributed to the old SWS shall not exceed 107.9 tons per year based on a rolling 12-calendar month total.

2. SRU Incinerator Stack (E-407 & INC-401)

a. SO_2 emissions from the SRU incinerator stack shall not exceed:

i. 53.17 tons/rolling 12-calendar month total,
ii. 341.04 lb/day, and
iii. 14.21 lb/hr (250 ppm, rolling 12-hour average corrected to 0% oxygen, on a dry basis).

b. NO_x emissions from the SRU incinerator stack shall not exceed:

i. 3.5 tons/rolling 12-calendar month total,
ii. 19.2 lb/day, and
iii. 0.8 lb/hr.

c. Refinery fuel gas burned in the SRU reheater (E-407) and incinerator (INC-401) shall not exceed 0.10 grains of hydrogen sulfide (H_2S) per dry standard cubic foot. CHS Inc. shall not fire fuel oil in this unit.

3. Compressor Gas Engine Stack (C-201B)

a. NO_x emissions from C-201B shall not exceed:

i. 30.43 tons/rolling 12-calendar month total, and
ii. 7.14 lb/hr.

b. Carbon monoxide (CO) emissions from C-201B shall not exceed:

i. 68.59 tons/rolling 12-calendar month total,
ii. 6.40 lb/hr when firing natural gas, and
iii. 16.10 lb/hr when firing propane.

c. VOC emissions from C-201B shall not exceed 10.1 tons/rolling 12 calendar-month total.

d. CHS Inc. shall only combust natural gas or propane in C-201B.

4. Fractionator Feed Heater Stack (H-202)

a. SO_2 emissions from H-202 shall not exceed:

i. 4.93 tons/rolling 12-calendar month total, and
ii. 1.24 lb/hr.

b. NO_x emissions from H-202 shall not exceed:

i. 8.34 tons/rolling 12 calendar-month total, and
ii. 2.09 lb/hr.

c. CO emissions from H-202 shall not exceed:

i. 6.42 tons/rolling 12-calendar month total, and
ii. 1.61 lb/hr.

d. VOC emissions from H-202 shall not exceed 0.51 tons/rolling 12-calendar month total.

e. Refinery fuel gas burned in H-202 shall not exceed 0.10 grains of H_2S per dry standard cubic foot. CHS Inc. shall not fire fuel oil in this unit.

5. Reactor Charge Heater Stack (H-201)

a. SO_2 emissions from H-201 shall not exceed:

i. 6.83 tons/rolling 12-calendar month total, and
ii. 1.72 lb/hr.

b. NO_x emissions from H-201 shall not exceed:

i. 11.56 tons/rolling 12-calendar month total, and
ii. 2.9 lb/hr.

c. CO emissions from H-201 shall not exceed:

i. 8.89 tons/rolling 12-calendar month total, and
ii. 2.23 lb/hr.

d. VOC Emissions from H-201 shall not exceed 0.71 tons/rolling 12-calendar month total.

e. Refinery fuel gas burned in H-201 shall not exceed 0.10 grains of H_2S per dry standard cubic foot. CHS Inc. shall not fire fuel oil in this unit.

6. Reformer Heater Stack (H-101)

a. SO_2 emissions from H-101 shall not exceed:

i. 3.35 tons/rolling 12-calendar month total, and
ii. 2.15 lb/hr.

b. NO_x emissions from H-101 shall not exceed:

i. 27.16 tons/rolling 12-calendar month total, and
ii. 6.78 lb/hr.

c. CO emissions from H-101 shall not exceed:

i. 13.93 tons/rolling 12-calendar month total, and
ii. 4.51 lb/hr.

d. VOC emissions from H-101 shall not exceed 0.35 tons/rolling 12-calendar month total.

e. Refinery fuel gas burned in H-101 shall not exceed 0.10 grains of H_2S per dry standard cubic foot. CHS Inc. shall not combust fuel oil in this unit.

D. Monitoring Requirements

1. CHS Inc. shall install and operate the following continuous emission monitors/continuous emission rate monitors (CEMS/CERMS):

a. SRU Incinerator Stack (E-407/INC-401)

i. SO_2
ii. Oxygen
iii. Volumetric Flow Rate

b. Fuel Gas Monitoring

Continuous concentration (dry basis) monitoring of H_2S in refinery fuel gas burned in the combustion devices listed in Section II.C.

2. CEMS and CERMS required by this permit shall comply with all applicable provisions of 40 CFR Parts 60.5 through 60.13, Subparts J, 60.100-108 and Appendix B, Performance Specifications 2, 3, 6, and 7 and Appendix F; and 40 CFR 52, Appendix E, for certifying Volumetric Flow Rate Monitors.

3. CEMS are to be in operation at all times when the emission units are operating, except for quality assurance and control checks, breakdowns, and repairs. Startup shall be considered to be when acid gas and SWS streams are first introduced into the sulfur recovery facility. In the event the primary CEMS is unable to meet minimum availability requirements, the recipient shall provide a back-up or alternative monitoring system and plan such that continuous compliance can be demonstrated.

E. Testing Requirements

1. The SRU Incinerator Stack (E-407 & INC-401) shall be tested annually, or according to another testing/monitoring schedule as may be approved by the Department, for SO_2 and NO_x, and the results submitted to the Department in order to demonstrate compliance with the SO_2 and NO_x emission limits contained in Section II.C.2.a and b (ARM 17.8.105 and ARM 17.8.749).

2. The Superior Clean Burn II 12 SGIB (C201-B) compressor engine shall be tested annually, or according to another testing/monitoring schedule as may be approved by the Department, for NO_x and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO_x

and CO emission limits contained in Section II.C.3.a and b (ARM 17.8.105 and ARM 17.8.749).

3. The Fractionator Feed Heater Stack (H-202) shall be tested annually, or according to another testing/monitoring schedule as may be approved by the Department, for NO_x and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO_x and CO emission limits contained in Section II.C.4.b. and c (ARM 17.8.105 and ARM 17.8.749).

4. The Reactor Charge Heater Stack (H-201) shall be tested annually, or according to another testing/monitoring schedule as may be approved by the Department, for NO_x and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO_x and CO emission limits contained in Section II.C.5.b and c (ARM 17.8.105 and ARM 17.8.749).

5. The Reformer Heater Stack (H-101) shall be tested annually, or according to another testing/monitoring schedule as may be approved by the Department, for NO_x and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the emission limits contained in Section II.C.6.b and c (ARM 17.8.105 and ARM 17.8.749).

6. All compliance source tests shall conform to the requirements of the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

7. The Department may require additional testing (ARM 17.8.105).

F. Compliance Determinations

1. In addition to the testing required in Section II.E, compliance determinations for hourly, 24-hour, and annual SO_2 limits for the SRU Incinerator stack shall be based upon CEMS data utilized for SO_2 as required in Sections II.D.1.a.

2. Compliance determinations for SO_2 limits for the fuel gas fired units within the HDS shall be based upon monitor data for H_2S, as required in Section II.D.1.b and fuel firing rates, if these units are fired on refinery fuel gas. Firing these units solely on natural gas shall demonstrate compliance with the applicable SO_2 limits.

3. In addition to the testing required in Section II.E, compliance determinations for the emission limits applicable to the HDS complex sources listed in Sections II.C.1 through 6 shall be based upon actual fuel burning rates and the emission factors developed from the most recent compliance source test. Fuel flow rates, fuel heating value, production information and other data, as needed, shall be recorded for each emitting unit during the performance of the source tests in order to develop emission factors for use in the compliance determinations. New emission factors shall become effective within 60 days after the completion of a source test. Firing these units solely on natural gas shall demonstrate compliance with the applicable VOC limits (ARM 17.8.749).

4. Compliance with the opacity limitation listed in Section II.B shall be determined using EPA reference method 9 testing by a qualified observer.

5. Emissions of NO_x and SO_2 attributed to the old SWS for determining compliance with the emission limits in Section II.C.1 shall be determined by twice-weekly

measurements of hydrogen sulfide and ammonia in the old SWS feed stream and in the "stripper bottoms." The chemical analysis frequency for the old SWS unit, when operated, shall be twice per 7 days of continuous operation or, at least once if operated less than 3 days. Flow meters shall be utilized to establish the feed and "bottoms" flow rates. Emissions of SO_2 and NO_x, attributed to the old SWS, shall be determined by applying these measurements in engineering calculations according to the procedures described in Attachment A. Reporting of the SO_2 and NO_x emission data shall be in accordance with Section II.G.1.

Non-operation of the old SWS shall be verified by physically chaining and locking the old SWS feed valve in a closed position. A signed operator log shall be maintained to verify locking and unlocking of the feed water valve. Copies of this log shall be submitted to the Department as part of the monthly emission report specified in Section II.G.

G. Operational and Emission Inventory Reporting Requirements (ARM 17.8.749)

1. CHS Inc. shall submit monthly emission reports to the Department based on data from the installed CEMS/CERMS. Emission reporting for SO_2 from the emission rate monitor shall consist of a daily 24-hour average (lb/hr) and a 24-hour total (lb/day) for each calendar day. CHS Inc. shall submit the monthly emission reports within 30 days of the end of each calendar month. Copies of the monthly emission report shall be submitted to both the Billings regional office and the Helena office of the Department. The monthly report shall also include the following:

   a. Source or unit operating time during the reporting period and monthly fuel gas consumption rates and 24-hour (daily) average concentration of H_2S in the refinery fuel gas burned at the permitted facilities.

   b. Monitoring downtime that occurred during the reporting period.

   c. A summary of excess emissions or applicable concentrations for each pollutant and the averaging period identified in Sections II.C.2 through 6.

   d. Emission rate determinations for SO_2 and NO_x from the operation of the old SWS unit reported as a rolling 12-calendar month total. Analysis results of ammonia and hydrogen sulfide concentrations for both the feed and bottoms. Copies of the operator log for the old SWS feed valve shall be submitted monthly.

   e. Compliance determinations for hourly, 24-hour, and annual limits specifically allowed in Sections II.C.2 through 6 (ARM 17.8.749).

   f. Reasons for any emissions in excess of those specifically allowed in Sections II.C.2 through 6 with mitigative measures utilized and corrective actions taken to prevent a recurrence of the situation.

2. CHS Inc. shall supply the Department with annual production information for all emission points, as required by the Department in the annual emission inventory request. The request will include, but is not limited to, all sources of emissions identified in the emission inventory contained in the permit analysis and sources identified in Section I of this permit.

Production information shall be gathered on a calendar-year basis and submitted to the Department by the date required in the emission inventory request. Information shall be in the units required by the Department. This information may be used for calculating operating fees, based on actual emissions from the facility, and/or to verify compliance with permit limitations (ARM 17.8.505).

3. CHS Inc. shall notify the Department of any construction or improvement project conducted, pursuant to ARM 17.8.745, that would include a change of control equipment, stack height, stack diameter, stack flow, stack gas temperature, source location, or fuel specifications, or would result in an increase in source capacity above its permitted operation or the addition of a new emissions unit. The notice must be submitted to the Department, in writing, 10 days prior to start up or use of the proposed de minimis change, or as soon as reasonably practicable in the event of an unanticipated circumstance causing the de minimis change, and must include information requested in ARM 17.8.745(1)(d) (ARM 17.8.745).

4. All records compiled in accordance with this permit must be maintained by CHS Inc. as a permanent business record for at least 5 years following the date of the measurement, must be available at the plant site for inspection by the Department, EPA, and the Yellowstone County Air Pollution Control Agency, and must be submitted to the Department upon request (ARM 17.8.749).

H. Notification Requirements

CHS Inc. shall provide the Department (both the Billings regional and the Helena offices) with written notification of the following dates within the following time periods (ARM 17.8.749 and 340):

1. All compliance source tests as required by the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

2. The Department must be notified promptly by telephone whenever a malfunction occurs that can be expected to create emissions in excess of any applicable emission limitation, or to continue for a period greater than 4 hours (ARM 17.8.110).

Section III: Limitations and Conditions for #10 Boiler

A. CHS Inc. shall comply with all applicable standards and limitations, and the monitoring, recordkeeping and reporting requirements contained in 40 CFR Part 60 for the #10 Boiler. The following subparts, at a minimum, are applicable (ARM 17.8.340):

1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.

2. Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units.

3. Subpart J - Standards of Performance for Petroleum Refineries. The requirements of this Subpart will apply to the #10 Boiler as of November 1, 1997.

4. Subpart GGG - Standards of Performance for Equipment leaks of VOC in Petroleum Refineries applies to the refinery fuel gas supply lines to the #10 Boiler.

B. Emission Limitations for #10 Boiler

1. The #10 Boiler shall be fired only on natural gas until November 1, 1997, at which time CHS Inc. will be allowed to fire refinery fuel gas in the boiler. H_2S concentration in the refinery fuel gas burned in the #10 Boiler shall not exceed 0.10 gr/dscf. Fuel oil burning is not allowed in this unit (ARM 17.8.340,ARM 17.8.749, and ARM 17.8.752,).

2. SO_2 emissions shall not exceed 3.83 lb/hr (ARM 17.8.752).

3. NO_x emissions shall not exceed 0.058 lb/MMBtu fired and 5.79 lb/hr (ARM 17.8.752).

4. CO emissions shall not exceed 0.10 lb/MMBtu fired and 9.99 lb/hr (ARM 17.8.752).

5. VOC emissions shall not exceed 0.015 lb/MMBtu fired and 1.50 lb/hr (ARM 17.8.752).

6. Opacity shall not exceed 20%, averaged over any 6 consecutive minutes (ARM 17.8.304).

7. The #10 Boiler shall not exceed 99.90 MMBtu/hour of heat input. The boiler shall be fitted with low NO_x burners with flue gas recirculation (FGR) and have a minimum stack height of 75 feet above ground level (ARM 17.8.340 and ARM 17.8.749).

C. Monitoring Requirements

1. CHS Inc. shall install, operate, and maintain a continuous H_2S concentration monitor, including a data acquisition system, to monitor and record the H_2S concentration of all refinery fuel gas burned in the #10 Boiler (ARM 17.8.340).

2. CHS Inc. shall install, operate, and maintain a continuous fuel gas flow rate meter, including a data acquisition system, to monitor and record the fuel flow rate of all fuel gas burned in the #10 Boiler (ARM 17.8.749).

3. The continuous H_2S concentration monitor shall comply with all applicable provisions of 40 CFR Parts 60.5 through 60.13, Subparts J, Appendix B, Performance Specifications 6 and 7, and Appendix F (Quality Assurance/Quality Control) provisions (ARM 17.8.340).

4. The continuous fuel gas flow rate meter shall meet the following specifications (ARM 17.8.749):

a. For each hour when the unit is combusting fuel, measure and record the flow of fuel combusted by the unit. Measure the flow of fuel with an in-line fuel flowmeter and automatically record the data with a data acquisition and handling system.

b. Each fuel flowmeter used shall meet a flowmeter accuracy of 2.0% of the upper range value (i.e., maximum calibrated fuel flow rate), either by design or as calibrated and as measured under laboratory conditions by the manufacturer, by an independent laboratory, or by the owner or operator.

c. The fuel gas flow rate meter shall meet the Fuel Gas Flowmeter Calibration and Quality Assurance Procedures outlined in Attachment C.

D. Testing Requirements

1. The #10 Boiler shall be tested for NO_x, CO, and VOC concurrently and the results submitted to the Department in order to demonstrate compliance with the NO_x, CO, and VOC limits contained in Section III.B within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after start up of the #10 Boiler (ARM 17.8.105 and ARM 17.8.106).

2. The #10 Boiler shall be tested for NO_x, CO, and VOC concurrently and the results submitted to the Department in order to demonstrate compliance with the NO_x, CO, and VOC limits contained in Section III.B within 60 days after start up of the boiler on refinery fuel gas (ARM 17.8.105 and ARM 17.8.106).

3. The #10 Boiler shall be tested for NO_x, CO, and VOC concurrently at a minimum of every 5 years or according to another testing/monitoring schedule as may be approved by the Department. Testing shall be conducted for both natural gas and refinery fuel gas (ARM 17.8.105 and ARM 17.8.106).

4. Fuel flow rates, fuel heating value, production information and other data, as needed, shall be recorded during the performance of source tests in order to develop emission factors for use in the compliance determinations of Section III.E (ARM 17.8.749).

5. All compliance source tests shall be conducted in accordance with the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

6. The Department may require additional testing (ARM 17.8.105).

E. Compliance Determinations

1. Compliance determinations for SO_2 and H_2S limits for the #10 Boiler shall be based upon continuous H_2S concentration monitor data and fuel gas flowmeter data as required in Section III.C. This compliance method, using H_2S concentration monitors data and fuel gas flowmeter data, will apply to the #10 Boiler as of November 1, 1997 (ARM 17.8.749).

2. In addition to the testing required in Section III.D, compliance determinations for NO_x, CO, and VOC emission limits for the #10 Boiler shall be based upon actual fuel burning rates and the emission factors developed from the most recent compliance source test of each fuel being combusted. New emission factors shall become effective within 60 days after the completion of a source test. Firing Boiler #10 solely on natural gas shall demonstrate compliance with the applicable VOC limits (ARM 17.8.749).

3. Compliance with the opacity limitations shall be determined according to 40 CFR, Part 60, Appendix A, Method 9 Visual Determination of Opacity of

Emissions from Stationary Sources (ARM 17.8.749).

F. Operational and Emission Inventory Reporting Requirements (ARM 17.8.749)

1. CHS Inc. shall provide monthly emission reports using data from continuous H_2S concentration monitors and fuel gas flowmeters. Reporting requirements shall be consistent with 40 CFR Part 60, or as specified by the Department (ARM 17.8.340). The monthly report shall also include the following:

   a. SO_2 emission data from the refinery fuel gas system continuous H_2S concentration monitor and continuous fuel gas flow rate meter required by Section III.C.2 and 3. The SO_2 emission rates shall be reported for the following averaging periods:

      i. Average lb/hr per calendar day,
      ii. Total lb per calendar day, and
      iii. Total tons per month.

   b. NO_x emission data from the continuous fuel gas flow rate meter and the emission factors developed from the most recent compliance source test required by Section III.C.2 and D.1 and 3. The NO_x emission rates shall be reported for the following averaging periods:

      i. Average lb/hr per calendar day,
      ii. Total lb per calendar day, and
      iii. Total tons per month.

   c. The daily and monthly total fuel gas consumption used to calculate the emission rates for boiler #10 shall be reported.

   d. Source or unit operating time during the reporting period and monthly refinery fuel gas and natural gas consumption rates and 24-hour (daily) average concentration of H_2S in the refinery fuel gas burned at the permitted facility.

   e. Monitoring downtime that occurred during the reporting period.

   f. An excess emission summary, which shall include excess emissions (lb/hr) for each pollutant and excess H_2S concentrations (gr/dscf) identified in Section III.B.

   g. Reasons for any emissions in excess of those specifically allowed in Section III.B with mitigative measures utilized and corrective actions taken to prevent a recurrence of the situation.

2. CHS Inc. shall submit monthly emission reports within 30 days of the end of each calendar month.

3. Copies of monthly emission reports, excess emissions, emission testing reports and other reports required by Sections III.D and III.F.1 shall be submitted to both the Billings regional office and the Helena office of the Department.

4. CHS Inc. shall comply with the reporting and recordkeeping requirements in 40 CFR 60.7 and 40 CFR 60.48c (a, g, and i). The maximum design heat input capacity shall be based on the highest gross calorific value (GCV) of each fuel to be combusted in boiler #10. CHS Inc. shall submit certification from the boiler manufacturer of the maximum design heat input capacity for the installed boiler. This certification shall include all design criteria used in determining the maximum design heat input capacity and provide reasons why this rate could not be exceeded. The Department may require recordkeeping and reporting requirements that may be necessary to demonstrate, on a continuing basis, that this maximum heat input capacity value is not being exceeded at any time.

5. CHS Inc. shall supply the Department with annual production information for all emission points, as required by the Department in the annual emission inventory request. The request will include, but is not limited to, all sources of emissions identified in the emission inventory contained in the permit analysis and sources identified in Section I of this permit.

   Production information shall be gathered on a calendar-year basis and submitted to the Department by the date required in the emission inventory request. Information shall be in the units as required by the Department. This information may be used for calculating operating fees, based on actual emissions from the facility, and/or to verify compliance with permit limitations (ARM 17.8.505).

6. All records compiled in accordance with this permit must be maintained by CHS Inc. as a permanent business record for at least 5 years following the date of the measurement, must be available at the plant site for inspection by the Department, EPA, and the Yellowstone County Air Pollution Control Agency, and must be submitted to the Department upon request (ARM 17.8.749).

7. CHS Inc. shall notify the Department of any construction or improvement project conducted, pursuant to ARM 17.8.745, that would include a change of control equipment, stack height, stack diameter, stack flow, stack gas temperature, source location, or fuel specifications, or would result in an increase in source capacity above its permitted operation or the addition of a new emission unit. The notice must be submitted to the Department, in writing, 10 days prior to start up or use of the proposed de minimis change, or as soon as reasonably practicable in the event of an unanticipated circumstance causing the de minimis change, and must include information requested in ARM 17.8.745(1)(d) (ARM 17.8.745).

G. Notification Requirements

CHS Inc. shall provide the Department (both the Billings regional and the Helena offices) with written notification of the following dates within the following time periods (ARM 17.8.340 and ARM 17.8.749):

1. Date of commencement of construction of the #10 Boiler within 30 days after commencement of construction.

2. Anticipated date of start up of the #10 Boiler, 30 to 60 days prior to the anticipated start-up date.

3. Actual date of start up of the #10 Boiler within 15 days after the actual start-up

date.

4. Actual date of start up of the #10 Boiler on refinery fuel gas within 15 days after the actual start-up date on refinery fuel gas.
5. Complete and submit Section 5.0 (Emitting Unit/Process Information) of the Montana Department of Environmental Quality Permit Application for Sources of Air Pollution. This information shall be submitted upon CHS Inc.'s selection decision of a boiler model, but before commencement of construction. This in no way eliminates the need for a permit alteration if the specifications for the selected boiler are different from the information submitted with the permit application.

6. The Department must be notified promptly by telephone whenever a malfunction occurs that can be expected to create emissions in excess of any applicable emission limitation, or to continue for a period greater than 4 hours (ARM 17.8.110).

Section IV: Limitations and Conditions for the Product Loading Rack Vapor Combustion Unit (VCU)

A. CHS Inc. shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements of ARM 17.8.342, as specified in 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants (NESHAP) for Source Categories.

1. Subpart A - General Provisions applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.

2. Subpart CC - NESHAP from Petroleum Refineries shall apply to, but not be limited to, the product loading rack and VCU.

3. The product loading rack and vapor combustion unit shall be operated and maintained as follows:

a. CHS Inc.'s product loading rack shall be equipped with a vapor collection system designed to collect the organic compound vapors displaced from cargo tanks during gasoline product loading (ARM 17.8.342).

b. CHS Inc.'s collected vapors shall be routed to the VCU at all times. In the event the VCU is inoperable, CHS Inc. may continue to load distillates, provided the Department is notified in accordance with the requirements of ARM 17.8.110 (ARM 17.8.749).

c. The vapor collection and liquid loading equipment shall be designed and operated to prevent gauge pressure in the gasoline cargo tank from exceeding 4,500 Pascals (Pa) (450 millimeters (mm) of water) during product loading. This level shall not be exceeded when measured by the procedures specified in the test methods and procedures in 40 CFR 60.503(d) (ARM 17.8.342).

d. No pressure-vacuum vent in the permitted terminal's vapor collection system shall begin to open at a system pressure less than 4,500 Pa (450 mm of water) (ARM 17.8.342).

e. The vapor collection system shall be designed to prevent any VOC vapors collected at one loading rack from passing to another loading rack (ARM 17.8.342).

f. Loadings of liquid products into gasoline cargo tanks shall be limited to vapor-tight gasoline cargo tanks, using the following procedures (ARM 17.8.342):

   i. CHS Inc. shall obtain annual vapor tightness documentation described in the test methods and procedures in 40 CFR 63.425(e) for each gasoline cargo tank that is to be loaded at the product loading rack.

   ii. CHS Inc. shall require the cargo tank identification number to be recorded as each gasoline cargo tank is loaded at the terminal.

   iii. CHS Inc. shall cross-check each tank identification number obtained during product loading with the file of tank vapor tightness documentation within 2 weeks after the corresponding cargo tank is loaded.

   iv. CHS Inc. shall notify the owner or operator of each non-vapor-tight cargo tank loaded at the product loading rack within 3 weeks after the loading has occurred.

   v. CHS Inc. shall take the necessary steps to ensure that any non-vapor-tight cargo tank will not be reloaded at the product loading rack until vapor tightness documentation for that cargo tank is obtained, which documents that:

      aa. The gasoline cargo tank meets the applicable test requirements in 40 CFR 63.425(e) to this permit.

      bb. For each gasoline cargo tank failing the test requirements in 40 CFR 63.425(f) or (g), the gasoline cargo tank must either:

         1. Before the repair work is performed on the cargo tank, meet the test requirements in 40 CFR 63.425 (g) or (h), or

         2. After repair work is performed on the cargo tank before or during the tests in 40 CFR 63.425 (g) or (h), subsequently pass the annual certification test described in 40 CFR 63.425(e).

g. CHS Inc. shall ensure that loadings of gasoline cargo tanks at the product loading rack are made only into cargo tanks equipped with vapor collection equipment that is compatible with the terminal's vapor collection system (ARM 17.8.342).

h. CHS Inc. shall ensure that the terminal's and the cargo tank's vapor recovery systems are connected during each loading of a gasoline cargo tank at the product loading rack (ARM 17.8.342).

i. The VCU stack shall be 35 feet above grade (ARM 17.8.749).

B. Emission Limitations for the Product Loading Rack VCU

1. The total VOC emissions to the atmosphere from the VCU due to loading liquid product into cargo tanks shall not exceed 10.0 milligrams per liter (mg/L) of gasoline loaded (ARM 17.8.342 and ARM 17.8.752).

2. The total CO emissions to the atmosphere from the VCU due to loading liquid product into cargo tanks shall not exceed 10.0 mg/L of gasoline loaded (ARM 17.8.752).

3. The total NO_x emissions to the atmosphere from the VCU due to loading liquid product into cargo tanks shall not exceed 4.0 mg/L of gasoline loaded (ARM 17.8.752).

4. CHS Inc. shall not cause or authorize to be discharged into the atmosphere from the enclosed VCU any visible emissions that exhibit an opacity of 20% or greater over any 6 consecutive minutes (ARM 17.8.304(2)).

C. Monitoring Requirements

1. CHS Inc. shall perform the testing and monitoring procedures specified in 40 CFR §§63.425 and 63.427 of Subpart R, except §63.425(d) or §63.427(c) (ARM 17.8.342).

2. CHS Inc. shall install and continuously operate a thermocouple and an associated recorder, or an ultraviolet flame detector and relay system, which will render the loading rack inoperable if a flame is not present at the VCU flare tip, or any other equivalent device, to detect the presence of a flame (ARM 17.8.342 and ARM 17.8.752).

3. CHS Inc. shall monitor and maintain all pumps, shutoff valves, relief valves and other piping and valves associated with the gasoline loading rack as described in 40 CFR 60.482-1 through 60.482-10.

D. Testing Requirements

1. CHS Inc. shall comply with all test methods and procedures as specified by Subpart R §63.425 (a) through (c), and §63.425 (e) through (h). This shall apply to, but not be limited to, the product loading rack, the vapor processing system, and all gasoline equipment located at the product loading rack.

2. The product loading rack VCU shall be initially tested for VOCs, and compliance demonstrated with the emission limitation contained in Section IV.B.1 within 180 days of initial startup and continue on an every 5-year basis or according to another testing/monitoring schedule as may be approved by the Department. CHS Inc. shall perform the test methods and procedures as specified in 40 CFR 63.425, Subpart R (ARM 17.8.105 and 17.8.342).

3. The product loading rack VCU shall be initially tested for CO and NO_x, concurrently, and compliance demonstrated with the CO and NO_x emission limitations contained in Section IV.B.2 and 3 within 180 days of initial start up (ARM 17.8.105).

4. Fuel flow rates, production information, and any other data the Department believes is necessary shall be recorded during the performance of source tests (ARM 17.8.749).

5. All compliance source tests shall be conducted in accordance with the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

6. The Department may require additional testing (ARM 17.8.105).

E. Operational and Emission Inventory Reporting Requirements

1. CHS Inc. shall supply the Department with the following reports, as required by 40 CFR Part 63 (ARM 17.8.342).

   a. Subpart CC - CHS Inc. shall keep all records and furnish all reports to the Department as required by 40 CFR Part 63.428 (b) and (c), (g)(1), and (h)(1) through (h)(3) of Subpart R.

   b. Subpart CC - CHS Inc. shall keep all records and furnish all reports to the Department as required by 40 CFR Part 63.654.

2. CHS Inc. shall supply the Department with annual production information for all emission points, as required by the Department in the annual emission inventory request. The request will include, but is not limited to, all sources of emissions identified in the emission inventory contained in the permit analysis and sources identified in Section I of this permit.

   Production information shall be gathered on a calendar-year basis and submitted to the Department by the date required in the emission inventory request. Information shall be in the units required by the Department. This information may be used for calculating operating fees, based on actual emissions from the facility, and/or to verify compliance with permit limitations (ARM 17.8.505).

3. CHS Inc. shall notify the Department of any construction or improvement project conducted, pursuant to ARM 17.8.745, that would include a change of control equipment, stack height, stack diameter, stack flow, stack gas temperature, source location, or fuel specifications, or would result in an increase in source capacity above its permitted operation or the addition of a new emissions unit. The notice must be submitted to the Department, in writing, 10 days prior to start up or use of the proposed de minimis change, or as soon as reasonably practicable in the event of an unanticipated circumstance causing the de minimis change, and must include information requested in ARM 17.8.745(1)(d) (ARM 17.8.745).

F. Notification Requirements

CHS Inc. shall provide the Department (both the Billings regional and Helena offices) with written notification of the following dates within the specified time periods (ARM

17.8.749):

1. Date of commencement of construction of the product loading rack VCU within 30 days after the commencement of construction.

2. Anticipated start-up date of the product loading rack VCU within 30 to 60 days prior to the actual start-up date.

3. Actual start-up date of the product loading rack VCU within 15 days after the actual start-up date.

4. All compliance source tests as required by the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

5. The Department must be notified promptly by telephone whenever a malfunction occurs that can be expected to create emissions in excess of any applicable emission limitations or can be expected to last for a period greater than 4 hours (ARM 17.8.110).

Section V: Limitations and Conditions for the No. 1 Crude Unit

A. CHS Inc. shall comply with all applicable standards and limitations, and the monitoring, recordkeeping and reporting requirements contained in 40 CFR Part 60 for the No. 1 Crude Unit. The following subparts, at a minimum, are applicable (ARM 17.8.340):

1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.

2. Subpart VV - Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry applies to the various new pumps, valves, flanges, and other equipment in Hazardous Air Pollutant (HAP) service within the No. 1 Crude Unit (40 CFR 63, Subpart CC: Maximum Achievable Control Technology (MACT) Standards for Petroleum Refineries).

B. Emission Control Requirements for No. 1 Crude Unit (ARM 17.8.752):

The No. 1 Crude Unit shall be maintained and operated as per the Leak Detection and Repair (LDAR) Program. The LDAR program would apply to new equipment in both HAP and non-HAP VOC service in the No. 1 Crude Unit. The LDAR program would not apply to existing equipment in non-HAP service undergoing retrofit measures.

CHS Inc. shall monitor and maintain all pumps, shutoff valves, relief valves and other piping and valves associated (as defined above) with the No. 1 Crude Unit as described in 40 CFR 60.482-1 through 60.482-10. Records of monitoring and maintenance shall be maintained on site for a minimum of 2 years.

C. Testing Requirements

1. All compliance source tests shall be conducted in accordance with the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

2. The Department may require testing (ARM 17.8.105).

D. Operational and Emission Inventory Reporting Requirements (ARM 17.8.749):

1. CHS Inc. shall supply the Department with annual production information for all emission points, as required by the Department in the annual emission inventory request. The request will include, but is not limited to, all sources of emissions identified in the emission inventory contained in the permit analysis and sources identified in Section I of this permit.

   Production information shall be gathered on a calendar-year basis and submitted to the Department by the date required in the emission inventory request. Information shall be in the units as required by the Department. This information may be used for calculating operating fees, based on actual emissions from the facility, and/or to verify compliance with permit limitations (ARM 17.8.505).

2. All records compiled in accordance with this permit must be maintained by CHS Inc. as a permanent business record for at least 5 years following the date of the measurement, must be available at the plant site for inspection by the Department, and must be submitted to the Department upon request (ARM 17.8.749).

3. CHS Inc. shall notify the Department of any construction or improvement project conducted, pursuant to ARM 17.8.745, that would include a change of control equipment, stack height, stack diameter, stack flow, stack gas temperature, source location, or fuel specifications, or would result in an increase in source capacity above its permitted operation or the addition of a new emission unit. The notice must be submitted to the Department, in writing, 10 days prior to start up or use of the proposed de minimis change, or as soon as reasonably practicable in the event of an unanticipated circumstance causing the de minimis change, and must include the information requested in ARM 17.8.745(1)(d) (ARM 17.8.745).

E. Notification Requirements

CHS Inc. shall provide the Department (both the Billings regional and the Helena offices) with written notification of the following dates within the following time periods (ARM 17.8.340 and ARM 17.8.749):

1. Date of commencement of the No. 1 Crude Unit Enhancement Project within 30 days after commencement of construction.

2. Actual date of start up of the No. 1 Crude Unit within 15 days after the actual start-up date.

3. The Department must be notified promptly by telephone whenever a malfunction occurs that can be expected to create emissions in excess of any applicable emission limitation, or to continue for a period greater than 4 hours (ARM 17.8.110).

Section VI: Limitations and Conditions for the ULSD Unit and Hydrogen Plant

A. CHS Inc. shall comply with all applicable standards and limitations, and the monitoring, recordkeeping, and reporting requirements contained in 40 CFR Part 60, Standards of Performance for NSPS. The following subparts, at a minimum, are applicable (ARM 17.8.340):

1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.

2. Subpart J - Standards of Performance for Petroleum Refineries applies to the two new ULSD Unit heaters (H-901 and H-902) and the Hydrogen Plant heater (H-801).

3. Subpart GGG - Standards of Performance for Equipment leaks of VOC in Petroleum Refineries applies to the ULSD Unit and the Hydrogen Plant fugitive piping equipment in VOC service.

4. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems applies to the ULSD Unit and Hydrogen Plant process drains.

B. CHS Inc. shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements specified in 40 CFR Part 63, NESHAP for Source Categories (ARM 17.8.342).

1. Subpart A – General Provisions applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.

2. Subpart CC – NESHAP from Petroleum Refineries shall apply to, but not be limited to, Tank 96 when it is brought into gasoline service.

3. Subpart DDDDD – Industrial Boilers and Process Heaters shall apply to, (as applicable after promulgation), but not be limited to, the Reactor Charge Heater (H-901), the Fractionation Heater (H-902), and the Hydrogen Reformer Heater (H-801).

C. CHS Inc. shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes. This applies to the sources in the ULSD Unit and Hydrogen Plant (ARM 17.8.304 (2)).

D. CHS Inc. shall not operate the ULSD Unit and Hydrogen Plant until the new TGTU for both the SRU #1 and #2 trains is permitted and in operation (ARM 17.8.749).

E. Limitations on Individual Sources (ARM 17.8.752)

1. Reactor Charge Heater H-901

a. SO_2 emissions from H-901 shall not exceed:

i. 3.90 tons/rolling 12-calendar month total, and
ii. 0.89 lb/hr.

b. NO_x emissions from H-901 shall not exceed:

i. 2.19 tons/rolling 12-calendar month total, and
ii. 0.50 lb/hr.

c. CO emissions from H-901 shall not exceed:

i. 33.79 tons/rolling 12-calendar month total, and
ii. 2.57 lb/hr.

d. VOC Emissions from H-901 shall not exceed 0.59 tons/rolling 12-calendar month total.

e. Refinery fuel gas burned in H-901 shall not exceed 0.10 grains of H_2S per dry standard cubic foot. CHS Inc. shall not fire fuel oil in this unit.

2. Fractionator Reboiler H-902

a. SO_2 emissions from H-902 shall not exceed:

i. 7.88 tons/rolling 12-calendar month total, and
ii. 1.80 lb/hr.

b. NO_x emissions from H-902 shall not exceed:

i. 4.40 tons/rolling 12-calendar month total, and
ii. 1.00 lb/hr.

c. CO emissions from H-902 shall not exceed:

i. 8.50 tons/rolling 12-calendar month total, and
ii. 1.94 lb/hr.

d. VOC Emissions from H-902 shall not exceed 1.19 tons/rolling 12-calendar month total.

e. Refinery fuel gas burned in H-902 shall not exceed 0.10 grains of H_2S per dry standard cubic foot. CHS Inc. shall not fire fuel oil in this unit.

3. Reformer Heater H-801

a. SO_2 emissions from H-801 shall not exceed:

i. 23.52 tons/rolling 12-calendar month total, and
ii. 5.37 lb/hr.

b. NO_x emissions from H-801 shall not exceed:

i. 26.28 tons/rolling 12-calendar month total, and
ii. 6.00 lb/hr.

c. CO emissions from H-801 shall not exceed:

i. 50.78 tons/rolling 12-calendar month total, and
ii. 11.59 lb/hr.

d. VOC Emissions from H-801 shall not exceed 6.97 tons/rolling 12-calendar month total.

e. Refinery fuel gas burned in H-801 shall not exceed 0.10 grains of H_2S

per dry standard cubic foot. CHS Inc. shall not fire fuel oil in this unit.

F. Monitoring Requirements (ARM 17.8.340).

1. CHS Inc. shall install and operate the following (CEMS/CERMS):

a. Fuel Gas Monitoring

CHS Inc. shall conduct continuous concentration (dry basis) monitoring of H_2S in refinery fuel gas burned in the combustion devices listed in Sections VI.E.1, 2, and 3.

b. Pressure Swing Absorption (PSA) Tail Gas Monitoring

CHS Inc. shall conduct continuous concentration (dry basis) monitoring of H_2S in the PSA tail gas line upstream of the combustion device listed in Section VI.E.3. In place of a continuous monitor, and Alternative Monitoring Plan, as approved by the Department, may be implemented.

2. CEMS are to be in operation at all times when the emission units are operating, except for quality assurance and control checks, breakdowns, and repairs. Startup shall be considered to be when a feed stream from the existing MDU process feeds including, raw diesel from #1 and #2 Crude Units, hydrotreated diesel from the Gas Oil Hydrotreater, light cycle oil from the Fluidized Catalytic Cracking Unit, and burner fuel from the #1 and #2 Crude units, is first introduced into the ULSD Unit and Hydrogen Plant. In the event the primary CEMS is unable to meet minimum availability requirements, the recipient shall provide a back-up or alternative monitoring system and plan such that continuous compliance can be demonstrated.

G. Testing Requirements

1. The Reactor Charge Heater (H-901) shall be tested annually, or according to another testing/monitoring schedule as may be approved by the Department, for NO_x and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO_x and CO emission limits contained in Section VI.E.1.b and c (ARM 17.8.105 and ARM 17.8.749).

2. The Fractionator Reboiler (H-902) shall be tested annually, or according to another testing/monitoring schedule as may be approved by the Department, for NO_x and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO_x and CO emission limits contained in Section VI.E.2.b and c (ARM 17.8.105 and ARM 17.8.749).

3. The Reformer Heater (H-801) shall be tested annually, or according to another testing/monitoring schedule as may be approved by the Department, for NO_x and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO_x and CO emission limits contained in Section VI.E.3.b and c (ARM 17.8.105 and ARM 17.8.749).

4. All compliance source tests shall conform to the requirements of the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

5. The Department may require additional testing (ARM 17.8.105).

H. Compliance Determinations (ARM 17.8.749).

1. Compliance determinations for the SO_2 limits for the fuel gas fired units within the ULSD Unit and the Hydrogen Plant shall be based upon fuel firing rates and the H_2S monitor data as required in Section VI.F.1.a, if these units are fired on refinery fuel gas. Firing these units solely on natural gas shall demonstrate compliance with the applicable SO_2 limits.

2. In addition to the testing required in Section VI.G, compliance determinations for the emission limits applicable to the ULSD Unit and Hydrogen Plant sources listed in Sections VI.E.1 through 3 shall be based upon actual fuel burning rates and the emission factors developed from the most recent compliance source test. Fuel flow rates, fuel heating value, production information and other data, as needed, shall be recorded for each emitting unit during the performance of the source tests in order to develop emission factors for use in the compliance determinations. New emission factors (subject to review and approval by the Department) shall become effective within 60 days after the completion of a source test (ARM 17.8.749).

3. Compliance with the opacity limitation listed in Section VI.C shall be determined using EPA reference method 9 testing by a qualified observer.

I. Operational and Emission Inventory Reporting Requirements (ARM 17.8.749)

1. Emission reporting for SO_2 from the emission rate monitors shall consist of a daily 24-hour average (lb/hr) and a 24-hour total (lb/day) for each calendar day. CHS Inc. shall submit the three monthly emission reports within 30 days of the end of each calendar quarter. Copies of the quarterly emission report shall be submitted to both the Billings regional office and the Helena office of the Department. The monthly report shall also include the following:

   a. Source or unit operating time during the reporting period and monthly fuel gas consumption rates and 24-hour (daily) average concentration of H_2S in the refinery fuel gas and PSA tail gas burned at the permitted facilities.

   b. Monitoring downtime that occurred during the reporting period.

   c. A summary of excess emissions or applicable concentrations for each pollutant and the averaging period identified in VI.E.1 through 3.

   d. Compliance determinations for hourly, 24-hour, and annual limits specifically allowed in VI.E.1 through 3.

   e. Reasons for any emissions in excess of those specifically allowed in VI.E.1 through 3 with mitigative measures utilized and corrective actions taken to prevent a recurrence of the situation.

2. CHS Inc. shall supply the Department with annual production information for all emission points, as required by the Department in the annual emission inventory request. The request will include, but is not limited to, all sources of emissions identified in the emission inventory contained in the permit analysis and sources identified in Section I of this permit.
Production information shall be gathered on a calendar-year basis and submitted to the Department by the date required in the emission inventory request. Information shall be in the units required by the Department. This information may be used for calculating operating fees, based on actual emissions from the facility, and/or to verify compliance with permit limitations (ARM 17.8.505).

3. CHS Inc. shall notify the Department of any construction or improvement project conducted, pursuant to ARM 17.8.745, that would include a change of control equipment, stack height, stack diameter, stack flow, stack gas temperature, source location, or fuel specifications, or would result in an increase in source capacity above its permitted operation or the addition of a new emissions unit. The notice must be submitted to the Department, in writing, 10 days prior to start up or use of the proposed de minimis change, or as soon as reasonably practicable in the event of an unanticipated circumstance causing the de minimis change, and must include information requested in ARM 17.8.745(1)(d) (ARM 17.8.745).

4. All records compiled in accordance with this permit must be maintained by CHS Inc. as a permanent business record for at least 5 years following the date of the measurement, must be available at the plant site for inspection by the Department, the EPA, and the Yellowstone County Air Pollution Control Agency, and must be submitted to the Department upon request (ARM 17.8.749).

J. Notification Requirements

CHS Inc. shall provide the Department (both the Billings regional and the Helena offices) with written notification of the following dates within the following time periods (ARM 17.8.340 and ARM 17.8.749):

1. All compliance source tests as required by the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

2. The Department must be notified promptly by telephone whenever a malfunction occurs that can be expected to create emissions in excess of any applicable emission limitation, or to continue for a period greater than 4 hours (ARM 17.8.110).

Section VII: Limitations and Conditions for the TGTU for Zone A's SRU #1 and SRU #2 trains

A. CHS Inc. shall comply with all applicable standards and limitations, and the monitoring, recordkeeping, and reporting requirements contained in 40 CFR Part 60, Standards of Performance for NSPS. The following subparts, at a minimum, are applicable (ARM 17.8.340):

1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.

2. Subpart J - Standards of Performance for Petroleum Refineries applies to Zone

A's SRU #1 and #2 tail gas incinerator (SRU-AUX-4) stack.

3. Subpart GGG - Standards of Performance for Equipment leaks of VOC in Petroleum Refineries applies to the TGTU fugitive piping equipment in VOC service.

4. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems applies to the TGTU process drains.

B. CHS Inc. shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements specified in 40 CFR Part 61, NESHAP. The following subparts, at a minimum, are applicable (ARM 17.8.342).

1. Subpart A – General Provisions applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.

2. Subpart FF – National Emission Standard for Benzene Waste Operations applies to the TGTU process wastewater streams. CHS Inc. will quantify the annual benzene quantity at the point of generation.

C. CHS Inc. shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements specified in 40 CFR Part 63, NESHAP for Source Categories (ARM 17.8.342).

1. Subpart A – General Provisions applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.

2. Subpart UUU – MACT Standard for Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units. CHS Inc. shall comply with Subpart UUU by complying with 40 CFR Part 60, NSPS Subpart J.

D. CHS Inc. shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes. This applies to the sources in the TGTU (ARM 17.8.304 (2)).

E. The Department determined, based on modeling provided by CHS Inc., that the SRU-AUX-4 stack shall be maintained at a height no less than 132 feet.

F. Limitations on SRU-AUX-4

1. SO_2 emissions from the SRU-AUX-4 stack shall not exceed:

a. 250 ppm, rolling 12-hour average corrected to 0% oxygen, on a dry basis,
b. 50.8 tons/rolling 12-calendar month total,
c. 11.60 lb/hr, and
d. 278.40 lb/day.

2. NO_x emissions from the SRU-AUX-4 stack shall not exceed:

a. 4.8 tons/rolling 12-calendar month total, and
b. 1.09 lb/hr.

3. Refinery fuel gas burned in the SRU Incinerator shall not exceed 0.10 grains of hydrogen sulfide (H_2S) per dry standard cubic foot. CHS Inc. shall not fire fuel oil in this unit.

G. Monitoring Requirements

1. CHS Inc. shall install and operate the following CEMS/CERMS:

   a. SRU-AUX-4 Stack

      i. SO_2
      ii. Oxygen
      iii. Volumetric Flow Rate

   b. Fuel Gas Monitoring

      Continuous concentration (dry basis) monitoring of H_2S in refinery fuel gas burned in the combustion devices listed in Section VII.F.1.

2. CEMS and CERMS required by this permit shall comply with all applicable provisions of 40 CFR Parts 60.5 through 60.13, Subparts J, 60.100-108 and Appendix B, Performance Specifications 2, 3, 6, and 7 and Appendix F. The volumetric flow rate monitor shall comply with the Billings/Laurel SIP Pollution Control Plan Exhibit A, Attachment 1 Methods A-1 and B-1.

3. CEMS are to be in operation at all times when the emission units are operating, except for quality assurance and control checks, breakdowns, and repairs. In the event the primary CEMS is unable to meet minimum availability requirements, the recipient shall provide a back-up or alternative monitoring system and plan such that continuous compliance can be demonstrated.

H. Testing Requirements

1. Initial testing shall be performed within 60 days of the date the TGTU achieves maximum production but not later than 180 days after start-up of the ULSD project The SRU-AUX-4 Stack shall be tested annually, or according to another testing/monitoring schedule as may be approved by the Department for SO_2, and shall be tested on an every-5-year basis, or according to another testing/monitoring schedule as may be approved by the Department, for NO_x. The results shall be submitted to the Department in order to demonstrate compliance with the SO_2 and NO_x emission limits contained in Section VII.F.1 and 2 (ARM 17.8.105 and ARM 17.8.749).

2. All compliance source tests shall conform to the requirements of the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

3. The Department may require additional testing (ARM 17.8.105).

I. Compliance Determinations (ARM 17.8.749)

1. In addition to the testing required in Section VII.H, compliance determinations for ppm concentration, hourly, 3-hour, 24-hour, and annual SO_2 limits for the SRU-AUX-4 Stack shall be based upon CEMS data utilized for SO_2 as required in Section VII.G.1.a.

2. Compliance with the opacity limitation listed in Section VII.D shall be determined using EPA reference method 9 testing by a qualified observer.

J. Operational and Emission Inventory Reporting Requirements (ARM 17.8.749)

1. Emission reporting for SO_2 from the emission rate monitors shall consist of a daily 24-hour average (lb/hr) and a 24-hour total (lb/day) for each calendar day. CHS Inc. shall submit the three monthly emission reports within 30 days of the end of each calendar quarter. Copies of the quarterly emission report shall be submitted to both the Billings regional office and the Helena office of the Department. The monthly report shall also include the following:

   a. Source or unit operating time during the reporting period and monthly fuel gas consumption rates and 24-hour (daily) average concentration of H_2S in the refinery fuel gas burned at the permitted facility.

   b. Monitoring downtime that occurred during the reporting period.

   c. A summary of excess emissions or applicable concentrations for each pollutant and the averaging period identified in VII.F.1.

   d. Compliance determinations for hourly, 24-hour, and annual limits specifically allowed in VII.F.1.

   e. Reasons for any emissions in excess of those specifically allowed in VII.F.1 with mitigative measures utilized and corrective actions taken to prevent a recurrence of the situation.

2. CHS Inc. shall supply the Department with annual production information for all emission points, as required by the Department in the annual emission inventory request. The request will include, but is not limited to, all sources of emissions identified in the emission inventory contained in the permit analysis and sources identified in Section I of this permit.

   Production information shall be gathered on a calendar-year basis and submitted to the Department by the date required in the emission inventory request. Information shall be in the units required by the Department. This information may be used for calculating operating fees, based on actual emissions from the facility, and/or to verify compliance with permit limitations (ARM 17.8.505).

3. CHS Inc. shall notify the Department of any construction or improvement project conducted, pursuant to ARM 17.8.745, that would include a change of control equipment, stack height, stack diameter, stack flow, stack gas temperature, source location, or fuel specifications, or would result in an increase in source capacity above its permitted operation or the addition of a new emissions unit. The notice must be submitted to the Department, in writing, 10 days prior to start up or use of the proposed de minimis change, or as soon as reasonably practicable in the event of an unanticipated circumstance causing the de minimis change, and must include information requested in ARM 17.8.745(1)(d) (ARM 17.8.745).

4. All records compiled in accordance with this permit must be maintained by CHS Inc. as a permanent business record for at least 5 years following the date of the measurement, must be available at the plant site for inspection by the Department, the EPA, and the Yellowstone County Air Pollution Control Agency, and must be submitted to the Department upon request (ARM 17.8.749).

K. Notification Requirements

CHS Inc. shall provide the Department (both the Billings regional and the Helena offices) with written notification of the following dates within the following time periods (ARM 17.8.340 and ARM 17.8.749):

1. All compliance source tests as required by the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

2. The Department must be notified promptly by telephone whenever a malfunction occurs that can be expected to create emissions in excess of any applicable emission limitation, or to continue for a period greater than 4 hours (ARM 17.8.110).

Section VIII: Plant-wide Refinery Limitations and Conditions

A. Annual Plant-wide Emission Limitations (ARM 17.8.749):

1.	SO_2 emissions shall not exceed	2980.3 tons per year (TPY)
2.	NO_x emissions shall not exceed	999.4 TPY
3.	CO emissions shall not exceed	530.7 TPY
4.	VOC emissions shall not exceed	1967.5 TPY
5.	PM_{10} emissions shall not exceed	152.2 TPY
6.	PM emissions shall not exceed	162.2 TPY

B. Compliance Determination (ARM 17.8.749):

CHS Inc. will track compliance with the emission caps based on source type, pollutant, calculation basis (emission factors, estimated yield and conversion), and key parameters (fuel oil use, fuel gas use, process gas use, and CEMS data). The units included in each source type are listed in Section I.A of the permit analysis.

1. Gas fired external combustion

a. SO_2

i. Calculation Basis: AP-42 Section 1-4 (7/98 revision) and complete conversion of fuel gas H_2S to SO_2

ii. Key Parameters: Monthly fuel use (scf) per combustion unit and refinery fuel gas H_2S content from CEMS.

b. NO_x, CO, PM_{10}/PM, VOC

i. Calculation Basis: AP-42 Section 1-4 (7/98 revision)

ii. Key Parameters: Monthly fuel use (scf) per combustion unit and monthly average fuel gas heat content.

2. Fuel oil fired external combustion

   a. SO_2

      i. Calculation Basis: Methodology required in the Billings-Laurel SO_2 SIP.
      ii. Key Parameters: Monthly fuel oil use (lb) per combustion unit and test for fuel oil Sulfur content pursuant to Billings-Laurel SO_2 SIP.

   b. NO_x, CO, PM_{10}/PM, VOC

      i. Calculation Basis: AP-42 Section 1-3 (9/98 revision including the 4/28/00 Errata)
      ii. Key Parameters: Monthly fuel oil use (lb) per combustion unit

3. Gas fired internal combustion

   a. SO_2

      i. Calculation Basis: AP-42 Section 1-4 (7/98 revision) and complete conversion of fuel gas H_2S to SO_2
      ii. Key Parameters: Monthly fuel use (scf) per combustion unit and fuel gas H_2S and Sulfur content

   b. NO_x, CO

      i. Calculation Basis: AP-42 Section 3-2 (10/96 revision)
      ii. Key Parameters: Monthly fuel use (scf) per combustion unit and monthly average fuel gas heat content

   c. PM_{10}/PM: Not applicable – not a significant source

   d. VOC

      i. Calculation Basis: AP-42 Section 3-2 (10/96 revision)
      ii. Key Parameters: Monthly fuel use (scf) per combustion unit and monthly average fuel gas heat content

4. #10 Boiler

   a. SO_2

      i. Calculation Basis: Complete conversion of fuel gas H_2S to SO_2
      ii. Key Parameters: Monthly fuel use (scf) per combustion unit and refinery fuel gas H_2S content from CEMS

   b. NO_x

      i. Calculation Basis: Emission factors based on stack tests
      ii. Key Parameters: NO_x stack tests, monthly fuel use (scf)

c. CO

i. Calculation Basis: Emission factors based on stack tests
ii. Key Parameters: CO stack tests, monthly fuel use (scf)

d. PM_{10}/PM

i. Calculation Basis: AP-42 Section 1-4 (7/98 revision)
ii. Key Parameters: Monthly fuel use (scf) and monthly average fuel gas heat content

e. VOC

i. Calculation Basis: Emission factors based on stack tests
ii. Key Parameters: VOC stack tests, monthly fuel use (scf)

5. Zone D combustion sources

a. SO_2: Calculation Basis: CEMS data and methodology required in the Billings/Laurel SO_2 SIP

b. NO_x

i. Calculation Basis: Emission factors based on annual stack tests
ii. Key Parameters: NO_x stack tests, monthly fuel use (scf) per combustion unit

c. CO

i. Calculation Basis: Emission factors based on annual stack tests
ii. Key Parameters: CO stack tests, monthly fuel use (scf) per combustion unit

d. PM_{10}/PM

i. Calculation Basis: AP-42 Section 1-4 (7/98 revision)
ii. Key Parameters: Monthly fuel use (scf) per combustion unit and monthly average fuel gas heat content

e. VOC

i. Calculation Basis: Emission factors based on annual stack tests for sources burning refinery fuel gas. For sources firing only natural gas, the most current VOC stack test will be used to develop emission factors.
ii. Key Parameters: VOC stack test

6. Fugitive equipment leaks

a. SO_2, NO_x, CO, PM_{10}/PM: Not applicable

b. VOC

i. Calculation Basis: EPA factors and NSPS and MACT control efficiencies (EPA-453/R-95-017)
ii. Key Parameters: Component counts by type and service

7. Fluid catalytic cracking (FCC) unit

a. SO_2: Calculation Basis: CEMS data and methodology required in Billings/Laurel SO_2 SIP
b. NO_x

i. Calculation Basis: AP-42 Section 5.1 (1/95 revision)
ii. Key Parameters: Monthly FCC charge rate (bbl)

c. CO: Maintain complete combustion (full-burn mode of operations) at the FCC unit

d. PM_{10}/PM

i. Calculation Basis: Site specific emission factor from catalyst mass balance studies
ii. Key Parameters: Monthly FCC charge rate (bbl)

e. VOC

i. Calculation Basis: AP-42 Section 5.1 (1/95 revision) and assumed 98% control efficiency
ii. Key Parameters: Monthly FCC charge rate (bbl)

8. Zone A SRU Incinerator

a. SO_2: Calculation Basis: CEMS data and methodology required in Billings/Laurel SO_2 SIP

b. NO_x, CO, PM_{10}/PM, VOC

i. Calculation Basis: AP-42 Section 1-4 (7/98 revision)
ii. Key Parameters: Monthly fuel use (scf) and average fuel gas heat content

9. Zone D SRU Incinerator

a. SO_2: Calculation Basis: CEMS data and methodology required in Billings/Laurel SO_2 SIP

b. NO_x

i. Calculation Basis: Emission factors based on annual stack tests
ii. Key Parameters: Annual NO_x stack test, monthly fuel use (scf)

c. CO, PM_{10}/PM, VOC: Not applicable – not a significant source

10. Old SWS

   a. SO_2: Calculation Basis: CEMS data and methodology required in Billings/Laurel SO_2 SIP

   b. NO_x

      i. Calculation Basis: Methodology listed in Attachment A
      ii. Key Parameters: Parameters described in Section II.F.5

   c. CO, PM_{10}/PM, VOC: Not applicable – not a source

11. Wastewater

   a. SO_2, NO_x, CO, PM_{10}/PM: Not applicable – not a source

   b. VOC

      i. Calculation Basis: AP-42, Table 5.1-2 (1/95 rev.)
      ii. Key Parameters: Monthly wastewater flow (gal) from Lab Information Management System (LIMS)

12. Cooling towers

   a. SO_2, NO_x, CO: Not applicable – not a source

   b. PM_{10}/PM: Not applicable – not included in the PM_{10}/PM emission cap

   c. VOC

      i. Calculation Basis: AP-42, Section 5.1 (1/95 rev.)
      ii. Key Parameters: Monthly cooling tower circulation (gal)

13. Loading facilities

   a. SO_2: Not applicable – not a source

   b. NO_x

      i. Calculation Basis: VCU stack tests for lb NO_x/gal loaded
      ii. Key Parameters: Monthly volume of materials loaded from yield accounting

   c. CO

      i. Calculation Basis: VCU stack tests for lb CO/gal loaded
      ii. Key Parameters: Monthly volume of materials loaded from yield accounting

   d. PM_{10}/PM: Not applicable – not a significant source

e. VOC

i. Calculation Basis: AP-42, Section 5.2-4 (1/95 rev.) and VCU stack tests for lb VOC/gal loaded
ii. Key Parameters: Monthly volume of material throughput from yield accounting, material property data (VP, MW, etc.)

14. Storage tanks

a. SO_2, NO_x, CO, PM_{10}/PM: Not applicable – not a source

b. VOC

i. Calculation Basis: EPA TANKS4.0
ii. Key Parameters: Monthly volume of material throughput from yield accounting, material property data (VP, MW, etc.)

C. Reporting and Recordkeeping Requirements (ARM 17.8.749):

CHS Inc. shall provide quarterly emission reports to demonstrate compliance with Section VIII.A using data required in Section VIII.B. The quarterly report shall also include CEMS monitoring downtime that occurred during the reporting period.

D. Testing Requirements

1. All compliance source tests shall be conducted in accordance with the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

2. The Department may require testing (ARM 17.8.105).

E. Operational and Emission Inventory Reporting Requirements (ARM 17.8.749):

1. CHS Inc. shall supply the Department with annual production information for all emission points, as required by the Department in the annual emission inventory request. The request will include, but is not limited to, all sources of emissions identified in the emission inventory contained in the permit analysis and sources identified in Section I of this permit.

   Production information shall be gathered on a calendar-year basis and submitted to the Department by the date required in the emission inventory request. Information shall be in the units as required by the Department. This information may be used for calculating operating fees, based on actual emissions from the facility, and/or to verify compliance with permit limitations (ARM 17.8.505).

2. All records compiled in accordance with this permit must be maintained by CHS Inc. as a permanent business record for at least 5 years following the date of the measurement, must be available at the plant site for inspection by the Department, and must be submitted to the Department upon request (ARM 17.8.749).

3. CHS Inc. shall notify the Department of any construction or improvement project conducted, pursuant to ARM 17.8.745, that would include a change of control equipment, stack height, stack diameter, stack flow, stack gas temperature, source

location, or fuel specifications, or would result in an increase in source capacity above its permitted operation or the addition of a new emission unit. The notice must be submitted to the Department, in writing, 10 days prior to start up or use of the proposed de minimis change, or as soon as reasonably practicable in the event of an unanticipated circumstance causing the de minimis change, and must include the information requested in ARM 17.8.745(1)(d) (ARM 17.8.745).

F. Notification Requirements

The Department must be notified promptly by telephone whenever a malfunction occurs that can be expected to create emissions in excess of any applicable emission limitation, or to continue for a period greater than 4 hours (ARM 17.8.110).

Section IX: General Conditions

A. Inspection - The recipient shall allow the Department's representatives access to the source at all reasonable times for the purpose of making inspections or surveys, collecting samples, obtaining data, auditing any monitoring equipment (CEMS, CERMS) or observing any monitoring or testing, and otherwise conducting all necessary functions related to this permit.

B. Waiver - The permit and all the terms, conditions, and matters stated herein shall be deemed accepted if the recipient fails to appeal as indicated below.

C. Compliance with Statutes and Regulations - Nothing in this permit shall be construed as relieving the permittee of the responsibility for complying with any applicable federal or Montana statute, rule, or standard, except as specifically provided in ARM 17.8.740, *et seq*. (ARM 17.8.756).

D. Enforcement - Violations of limitations, conditions and requirements contained herein may constitute grounds for permit revocation, penalties, or other enforcement as specified in Section 75-2-401 *et seq*., MCA.

E. Appeals - Any person or persons jointly or severally adversely affected by the Department's decision may request, within 15 days after the Department renders its decision, upon affidavit setting forth the grounds therefore, a hearing before the Board of Environmental Review (Board). A hearing shall be held under the provisions of the Montana Administrative Procedures Act. The Department's decision on the application is not final unless 15 days have elapsed and there is no request for a hearing under this section. The filing of a request for a hearing postpones the effective date of the Department's decision until the conclusion of the hearing and issuance of a final decision by the Board.

F. Permit Inspection - As required by ARM 17.8.755, Inspection of Permit, a copy of the air quality permit shall be made available for inspection by Department personnel at the location of the permitted source.

G. Construction Commencement - Construction must begin within 3 years of permit issuance and proceed with due diligence until the project is complete or the permit shall be revoked.

H. Permit Fees - Pursuant to Section 75-2-220, MCA, as amended by the 1991 Legislature, the continuing validity of this permit is conditional upon the payment by the permittee of an annual operation fee, as required by that section and rules adopted thereunder by the Board.

ATTACHMENT A[1]

EXISTING SOUR WATER STRIPPER (OLD SWS) EMISSIONS DETERMINATIONS

Required Data:

1. Feed Flow Rate - Totalized Flow Meter
2. Stripper Bottoms Flow Rate - Totalized Flow Meter
3. Feed H_2S Concentration - Standard Methods[2] 16th ED 427D
4. Feed NH_3 Concentration - Standard Methods 16th ED 417B
5. Bottoms H_2S Concentration - Standard Methods 16th ED 427C
6. Bottoms NH_3 Concentration - Standard Methods 16th ED 417B

Calculations:

(Feed Flow Rate, lb/day) (Concentration) = lb/day H_2S or NH_3

(Bottoms Flow Rate, lb/day) (Concentration) = lb/day H_2S or NH_3

(lb/day H_2S or NH_3 in Feed) - (lb/day H_2S or NH_3 in Bottoms)
=lb/day H_2S or NH_3 Emitted

lb/day H_2S Emitted * 64/34 = lb/day SO_2 Emitted

lb/day NH_3 Emitted * 46/17 * 0.5 = lb/day NO_2 Emitted

1 Copied from a memo from CHS Inc. dated April 16, 1992. Attachment A is a requirement from the HDS Complex permit.

2 The Standard Methods 16th Ed. 427D, 417B, and 427C were included as an attachment to the April 16, 1992, memo from CHS Inc. and a copy can be found as an attachment to Permit #1821-01 or from the Department.

ATTACHMENT C

FUEL GAS FLOWMETER CALIBRATION AND QUALITY ASSURANCE PROCEDURES FOR #10 BOILER

1. Use the procedures in the following standards for flowmeter calibration or flowmeter design, as appropriate to the type of flowmeter:

   ASME MFC-4M-1986 (Reaffirmed 1990), "Measurement of Gas Flow by Turbine Meters."

   American Gas Association Report No. 3, "Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids Part 1: General Equations and Uncertainty Guidelines" (October 1990 Edition), Part 2: "Specification and Installation Requirements" (February 1991 Edition) and Part 3: "Natural Gas Applications" (August 1992 edition), (excluding the modified flow-calculation method in Part 3).

   ASME MFC-7M-1987 (Reaffirmed 1992), "Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles."

2. The Department may also approve other procedures that use equipment traceable to National Institute of Standards and Technology (NIST) standards. Document other procedures, the equipment used, and the accuracy of the procedures in the monitoring plan. If the flowmeter accuracy exceeds 2.0 percent of the upper range value, the flowmeter does not qualify for use.

3. Alternatively, a fuel flowmeter used for the purposes of this part may be calibrated or recalibrated at least annually by comparing the measured flow of a flowmeter to the measured flow from another flowmeter that has been calibrated or recalibrated during the previous 365 days using a standard listed in item 1 or 2 of this Attachment. Any secondary elements, such as pressure and temperature transmitters, must be calibrated immediately prior to the comparison. Perform the comparison over a period of no more than seven consecutive unit operating days. Compare the average of three fuel-flow readings for each meter at each of three different flow levels, corresponding to (1) normal full operating load, (2) normal minimum operating load, and (3) a load point approximately equally spaced between the full and minimum operating loads. Calculate the flowmeter accuracy at each of the three flow levels using the following equation:

   $ACC = (R - A)/URV * 100$

   Where:
   ACC =Flow meter accuracy as a percentage of the upper range value.
   R =Average of the three flow measurements of the reference flow meter.
   A =Average of the three measurements of the flow meter being tested.
   URV =Upper range value of fuel flow meter being tested (i.e., maximum measurable flow).

4. If the flow meter accuracy exceeds 2.0 percent of the upper range value at any of the three flow levels, either recalibrate the flow meter until the accuracy is within the performance specification, or replace the flow meter with another one that is within the performance specification. Notwithstanding the requirement for annual calibration of the reference flowmeter, if a reference flowmeter and the flowmeter being tested are within 1.0 percent of the flow rate of each other during all in-place calibrations in a calendar year, then the reference flowmeter does not need to be calibrated before the next in-place calibration. This exception to calibration requirements for the reference flowmeter may be extended for periods up to five calendar years.

5. Recalibrate each fuel flowmeter to a flowmeter accuracy of 2.0 percent of the upper range value prior to use under this part at least annually, or more frequently if required by manufacturer specifications. Perform the recalibration using the procedures in item 1 of this Attachment.

6. For orifice-, nozzle-, and venturi-type flowmeters, also recalibrate the flowmeter the following calendar quarter using the procedures in item 7 of this Attachment, whenever the fuel flowmeter accuracy during a calibration or test is greater than 1.0 percent of the upper range value, or whenever a visual inspection of the orifice, nozzle, or venturi identifies corrosion since the previous visual inspection.

7. For orifice-, nozzle-, and venturi-type flowmeters that are designed according to the standards in item 1 of this Attachment, satisfy the calibration requirements of this Attachment by calibrating the differential pressure transmitter or transducer, static pressure transmitter or transducer, and temperature transmitter or transducer, as applicable, using equipment that has a current certificate of traceability to NIST standards. In addition, conduct a visual inspection of the orifice, nozzle, or venturi at least annually.

8. Other procedures, standards, or methods may be substituted upon approval from the Department.

Permit Analysis
CHS Inc. – Laurel Refinery
Permit #1821-10

I. Introduction/Process Description

A. Site Location/Description

The CHS Inc. Laurel Refinery is a petroleum refinery located in the South ½ of Section 16, Range 24 East, Township 2 South, in Yellowstone County. A complete list of permitted equipment is available in the permit, with the exception of the source categories for the Plant-wide Applicability Limit (PAL), which are listed below.

1. Gas-fired external combustion source type includes: #1 crude heater, crude preheater, #1 vacuum heater, #2 crude heater, #2 vacuum heater, Alky hot oil heater, platformer charge heater, platformer debutanizer heater, Fluid Catalytic Cracking (FCC) feed preheater, #1 naphtha unifier (NU) charge heater, NU splitter heater, #1 NU stripper heater, #2 NU heater, PDA heater, #1 road oil/asphalt loading heater, #2 road oil heater, BP2 heater, 60 tank heater, #1 fuel can heater, #3 boiler, #4 boiler, #5 boiler, #9 boiler, carbon monoxide (CO) boiler, Ultra Low Sulfur Diesel (ULSD) Unit Reactor charge heater, H-901, ULSD Unit Fractionation heater, H-902, and Hydrogen Plant Reformer heater, H-801

2. Fuel oil fired external combustion sources: #3 boiler, #4 boiler, #5 boiler, #1 crude heater)

3. Gas fired internal combustion sources: Platformer recycle turbine, #1 and #2 unifier compressors

4. #10 Boiler

5. Zone D combustion sources: H-101, H-201, H-202, C-201B

6. Fugitive equipment leaks include all equipment, as defined in 40 CFR 60, Subpart VV, in hydrocarbon service

7. FCC unit

8. Zone A Sulfur Recovery Unit (SRU) Tail Gas Incinerator (SRU-AUX-4) Stack source type includes: #1 SRU, #2 SRU Tail Gas Treatment Unit (TGTU)

9. Zone D SRU Incinerator

10. Old sour water stripper (SWS)

11. Wastewater source type includes: old American Petroleum Institute (API) separator, Zone D API separator, ULSD Unit Wastewater, TGTU Wastewater

12. Cooling tower sources: #1 cooling tower (CT), #2 CT, #3 CT, and #5 CT

13. Loading facilities: light product truck rack and VCU, heavy oil truck rack, heavy oil rail rack

14. Storage tanks: tank numbers 2, 6, 7, 9, 12, 28, 41, 47, 56, 60, 61, 62, 63, 64, 65, 66, 67, 68, 70, 73, 74, 75, 76, 77, 78, 79, 80, 81, 82, 83, 85, 86, 88, 91, 92, 93, 94, 95, 96, 100, 101, 102, 103, 104, 108, 109, 110, 111, 112, 113, 114, 117, 118, 120, 121, 122, 123, 128, B-1, B-2, B-7, BP-2, firetk 2, firetk 3, firetk 4, TGTU-VSSL-6

B. Permit History

On May 11, 1992, Cenex Harvest States Cooperatives (Cenex) was issued **Permit #1821-01** for the construction and operation of a hydro-treating process to desulfurize FCC Unit feedstocks. The existing refinery property lies immediately south of the City of Laurel and about 13 miles southwest of Billings, Montana. The new equipment for the desulfurization complex is located near the western boundary of the existing refining facilities.

The hydrodesulfurization (HDS) process is utilized to pretreat FCCU feeds by removing metal, nitrogen, and sulfur compounds from these feeds. The proposed HDS unit also improved the quality of refinery finished products including gasoline, kerosene, and diesel fuel. The HDS project significantly improved the finished product quality by reducing the overall sulfur contents of liquid products from the Cenex Refinery. The HDS unit provided low sulfur gas-oil feedstocks for the FCCU, which resulted in major reductions of sulfur oxide emissions to the atmosphere. However, only a minor quantity of the proposed sulfur dioxide (SO_2) emission reductions were made federally enforceable.

The application was not subject to the New Source Review (NSR) program for either nonattainment or Prevention of Significant Deterioration (PSD) since Cenex chose to "net out of major modification review" for the affected pollutants due to contemporaneous emission reductions at an existing emission unit.

The application was deemed complete on March 24, 1992. Additional information was received on April 16, 1992, in which Cenex proposed new short-term emission rates based upon modeled air quality impacts.

The basis for the permit application was due to a net contemporaneous emissions increase that was less than the significant level of 40 tons per year for SO_2 and nitrogen oxides (NO_x). The application referred to significant SO_2 emission reductions, which were expected by addition of the HDS project. These anticipated major SO_2 reductions were not committed to by Cenex under federally enforceable permit conditions and limitations. The contemporaneous emissions decrease for SO_2 and NO_x, which were made federally enforceable under this permitting action, amount to approximately 15.5 and 23.7 tons per year, respectively.

Construction of the HDS/sulfur recovery complex was completed in December 1993 and the 180-day-shakedown period ended in June 1994.

Permit #1821-02 was issued on February 1, 1997, to authorize the installation of an additional boiler (#10 Boiler) to provide steam for the facility. Cenex submitted the original permit application for a 182.50-MMBtu/hr boiler on February 9, 1996. This size boiler is a New Source Performance Standard (NSPS) affected facility and the requirements of NSPS Subpart Db would have applied to the boiler. On November 15, 1996, Cenex submitted a revised permit application proposing a smaller boiler (99.90 MMBtu/hr). The manufacturer of the proposed boiler has not been identified; however, the boiler is to be rated at approximately 80,000 lbs steam/hour with a heat input of 99.9 MMBtu/hour. The boiler shall has a minimum stack height of 75 feet above ground level. The boiler will be fired on natural gas until November 1, 1997, at which time Cenex will be allowed to fire refinery fuel gas in the boiler. The requirements of NSPS Subpart Dc apply to the boiler. The requirements of NSPS Subpart J and GGG will also apply as of November 1, 1997. Increases in emissions from the new boiler are detailed in Section IV of the permit analysis for Permit #1821-02. Modeling performed has shown that the emission increase will not result in a significant impact to the ambient air quality (see Section VI of the permit analysis).

Cenex has also requested a permit alteration to remove the SO_2 emission limits (Section II.E.2.a of Permit #1821-01) for the C-201B compressor engine because the permit already limits C-201B to be fired on either natural gas or unodorized propane. Cenex also requested that if the SO_2 emission limits could not be removed, the limits should be corrected to allow for the combustion of natural gas and propane. The Department of Environmental Quality (Department) has altered the permit to allow for burning odorized propane in the C-201B compressor.

Cenex also requested a permit modification to change the method of determining compliance with the HDS Complex emitting units. Permit #1821-01 requires that compliance with the hourly (lb/hr) emission limits be determined through annual source testing and that the daily (lb/day), annual (ton/yr), and Administrative Rules of Montana (ARM) 17.8 Subchapter 8 requirements (i.e., PSD significant levels and review) be determined by using actual fuel burning rates and the manufacturer's guaranteed emission factors listed in Attachment B. Cenex has requested to use actual fuel burning rates and fixed emission factors determined from previous source test data in order to determine compliance with the daily (lb/day) and annual (ton/yr) emission limits. The Department agrees that actual stack testing data is preferred to manufacturer's data for the development of emission factors. However, the Department is requiring that the emission factor be developed from the most recent source test and not on an average of previous source tests. The permit has been changed to remove Attachment B and rely on emission factors derived from the most recent source test, along with actual fuel flow rates for compliance determinations. However, in order to determine compliance with ARM 17.8 Subchapter 8, Cenex shall continue to monitor the fuel gas flow rates in both scf/hr and scf/year.

This Permit (#1821-02) was written to maintain the language from the HDS Complex Permit #1821-01, where possible, and to separate the HDS Complex Permit #1821-01 requirements from the requirements for the current action (boiler #10). The permit requirements from Permit #1821-01 have been included in Permit #1821-02.

On June 4, 1997, Cenex was issued **Permit #1821-03** to modify emissions and operational limitations on components in the Hydrodesulfurization Complex at the Laurel refinery. The unit was originally permitted in 1992, but has not been able to operate adequately under the emissions and operational limitations originally proposed by Cenex and permitted by the Department. This permitting action corrected these limitations and conditions. The new limitations established by this permitting action were based on operational experience and source testing at the facility and the application of Best Available Control Technology (BACT).

The following emission limitations were modified by this permit.

Source	Pollutant	Previous Limit	New Limit
SRU Incinerator stack (E-407 & INC-401)	SO_2	291.36 lb/day	341.04 lb/day
	NO_x	2.1 ton/yr 11.52 lb/day 0.48 lb/hr	3.5 ton/yr 19.2 lb/day 0.8 lb/hr
Compressor (C201-B)	NO_x	18.42 ton/yr	30.42 ton/yr
		6.26 lb/hr	7.14 lb/hr
	CO	16.45 ton/yr	68.6 ton/yr
		5.15 lb/hr - when on natural gas	6.4 lb/hr - when on natural gas
	VOC	6.26 ton/yr	10.1 ton/yr
Fractionator Feed Heater (H-202)	SO_2	0.53 ton/yr	4.93 ton/yr
		0.135 lb/hr	1.24 lb/hr
	NO_x	6.26 ton/yr	8.34 ton/yr
		1.43 lb/hr	2.09 lb/hr
	CO	3.29 ton/yr	6.42 ton/yr
		1.00 lb/hr	1.61 lb/hr
	VOC	0.26 ton/yr	0.51 ton/yr
Reactor Charge Heater (H-201)	SO_2	0.214 lb/hr	1.716 lb/hr
		0.79 ton/yr	6.83 ton/yr
	NO_x	9.24 ton/yr	11.56 ton/yr
		2.11 lb/hr	2.90 lb/hr
H-201 (cont.)	CO	4.86 ton/yr	8.89 ton/yr
		1.40 lb/hr	2.23 lb/hr
	VOC	0.39 ton/yr	0.71 ton/yr
Reformer Heater (H-101)	SO_2	0.128 lb/hr	2.15 lb/hr
		0.48 ton/yr	3.35 ton/yr
	NO_x	6.16 lb/hr	6.78 lb/hr
	VOC	0.24 ton/yr	0.35 ton/yr
Old Sour Water Stripper	SO_2	304.2 ton/yr	290.9 ton/yr
	NO_x	125.7 ton/yr	107.9 ton/yr

Emission limitations in this permit are based on the revised heat input capacities for units within the HDS. The following changes were made to the operational requirements of the facility.

Unit	Originally Permitted Capacity	New Capacity
SRU Incinerator stack (E-407 & INC-401)	4.8 MMBtu/hr	8.05 MMBtu/hr
Compressor (C201-B)	1600 hp (short term) 1067 hp (annual average)	1800 hp (short term and annual average)
Fractionator Feed Heater (H-202)	27.2 MMBtu/hr (short term) 20.4 MMBtu/hr(annual avg.)	29.9 MMBtu/hr (short term) 27.2 MMBtu/hr (annual avg.)
Reactor Charge Heater (H-201)	37.7 MMBtu/hr (short term) 30.2 MMBtu/hr (annual avg.)	41.5 MMBtu/hr (short term) 37.7 MMBtu/hr (annual avg.)
Reformer Heater	123.2 MMBtu/hr (short term and	135.5 MMBtu/hr (short term)

(H-101)	annual avg.)	123.2 MMBtu/hr (annual avg)

It has been determined that the emission and operational rates proposed during the original permitting of the HDS unit were incorrect and should have been at the levels Cenex is now proposing. Because of this, the current action and the original permitting of the HDS must be considered one project in order to determine the permitting requirements. When combined with the original permitting of the HDS, the emission increases of NO_x and SO_2 would exceed significant levels and subject this action to the requirements of the NSR/PSD program. During the original permitting of the HDS complex, Cenex chose to "net out" of NSR and PSD review by accepting limitations on the emissions of NO_x and SO_2 from the old SWS. Because of the emission increases proposed in this permitting action, additional emission reductions must occur. Cenex has proposed additional reductions in emissions from the old SWS to offset the increases allowed by this permitting action. These limitations will reduce the "net emission increase" to less than significant levels and negate the need for review under the NSR/PSD program.

The new emission limits for SO_2 and NO_x from the old SWS are 290.9 and 107.9 tons per year, respectively.

This permitting action also removes the emission limits and testing requirements for PM_{10} on the HDS heaters (H-101, H-201, and H-202). These heaters combust refinery gas, natural gas and PSA gas. The Department has determined that potential PM_{10} emissions from these fuels are minor and that emission limits and the subsequent compliance demonstrations for this pollutant are unnecessary.

Also removed from this permit are the compliance demonstration requirements for SO_2 and volatile organic compounds (VOC) when the combustion units are firing natural gas. The Department has determined that firing the units solely on natural gas will, in itself, demonstrate compliance with the applicable limits.

This action will result in an increase in allowable emissions of VOC and CO by 4.7 tons per year and 60 tons per year, respectively. Because of the offsets provided by reducing emissions from the old SWS, this permitting action will not increase allowable emissions of SO_2 or NO_x from the facility.

The following changes have been made to the Department's preliminary determination (PD) in response to comments from Cenex.

1. The emission limits for the old SWS in Section II.D.2 have been revised to ensure that the required offsets are provided without putting Cenex in a non-compliance situation at issuance of the permit. The compliance determinations of Section II.G.5 and the reporting requirements of Section II.H.1.d were also changed to reflect this requirement.

2. The CO emission limits for H-201 in Section II.D.6 have been revised; the old limits were inadvertently left in the PD. The table in Section I.B of the analysis has also been changed to reflect this.

3. Section III.E.2 was changed to clarify that the firing of natural gas would show compliance with the VOC emission limits for Boiler #10.

4. Section F. of the General Conditions was removed because the Department has placed the applicable requirements from the permit application into the permit.

5. Numbering has been changed in Section III.

Permit #1821-04 was issued to Cenex on March 6, 1998, in order to comply with the gasoline loading rack provisions of 40 CFR 63, Subpart CC - National Emission Standards for Petroleum Refineries, by August 18, 1998. Cenex proposed to install a gasoline vapor collection system and enclosed flare for the reduction of HAPs resulting from the loading of gasoline. A vapor combustion unit (VCU) was added to the product loading rack. The gasoline vapors would be collected from the trucks during loading, then routed to an enclosed flare where combustion would occur. The result of this project would be an overall reduction in the amount of VOCs (503.7 TPY) and HAPs emitted, but CO and NO_x emissions would increase slightly (4.54 TPY and 1.82 TPY).

The product loading rack is used to transfer refinery products (gasoline, burner and/or diesel fuels) from tank storage to trucks, which transport gasoline and other products, to retail outlets. The loading rack consists of three arms, each with a capacity of 500 gpm. However, only two loading arms are presently used for loading gasoline at any one time. A maximum gasoline-loading rate of 2000 gpm, a maximum short-term rate, was modeled to account for future expansion.

Because Cenex's product loading rack VCU is defined as an incinerator under MCA 75-2-215, a determination that the emissions from the VCU would constitute a negligible risk to public health was required prior to the issuance of a permit to the facility. Cenex and the Air and Waste Management Bureau (AWMB) identified the following hazardous air pollutants from the flare, which were used in the health risk assessment. These constituents are typical components of Cenex's gasoline:

1. Benzene
2. Toluene
3. Ethyl Benzene
4. Xylenes
5. Hexane
6. 2,2,4 Trimethlypentane
7. Cumene
8. Napthalene
9. Biphenyl

The reference concentration for Benzene was obtained from Environmental Protection Agency's (EPA) IRIS database. The ISCT3 modeling performed by Cenex, for the hazardous air pollutants identified above, demonstrated compliance with the negligible risk requirement.

Permit #1821-05 was issued to Cenex on September 3, 2000, to revamp its No. 1 Crude Unit in order to increase crude capacity, improve product quality, and enhance energy recovery. The project involved the replacement and upgrade of various heat exchangers, pumps, valves, towers, and other equipment. Only VOC emissions were affected by the new equipment. The capacity of the No. 1 Crude Unit was expected to increase by 10,000 or more barrels per stream day.

No increase in allowable emissions was sought under this permit application. The project would actually decrease VOC emissions from the No. 1 Crude Unit. However, increasing the capacity of the No. 1 Crude Unit was expected to increase the current utilization of other units throughout the refinery and thus possibly increase actual site-wide emissions, as compared to previous historical levels. Therefore, the permit included enforceable limits, requested by Cenex, on future site-wide emissions. The limits allow emission increases to remain below the applicable significant modification thresholds that trigger the NSR program for PSD and Nonattainment Area (NAA) permitting.

The site-wide limits were calculated based on the addition of the PSD/NAA significance level for each particular pollutant to the actual refinery emissions from April 1998, through March 2000, for SO_2, NO_x, CO, particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}), and particulate matter (PM) minus 0.1 ton per year (TPY) to remain below the significance level. A similar methodology was used for the VOC emissions cap, except that baseline data from the time period 1993 and 1999 were used to track creditable increases and decreases in emissions. The site-wide limits are listed in the following table.

Pollutant	Period Considered for Prior Actual Emissions	Average Emissions over 2-yr Period (TPY)	PSD/NAA Significance Level (TPY)	Proposed Emissions Cap (TPY)
SO_2	April 1998-March 2000	2940.4	40	2980.3
NO_x	April 1998-March 2000	959.5	40	999.4
CO	April 1998-March 2000	430.8	100	530.7
VOC	1993-1999	1927.6	40	1967.5
PM_{10}	April 1998-March 2000	137.3	15	152.2
PM	April 1998-March 2000	137.3	25	162.2

For example, the SO_2 annual emissions cap was calculated as follows:

Average refinery-wide SO_2 emissions in the period of April 1998 through 2000 added to the PSD/NAA significance level for SO_2 minus 0.1 TPY =

2940.4 TPY + 40 TPY – 0.1 TPY = 2980.3 TPY = Annual emissions cap.

Permit #1821-05 replaced Permit #1821-04.

Permit #1821-06 was issued on April 26, 2001, for the installation and operation of eight temporary, portable Genertek reciprocating engine electricity generators and two accompanying distillate fuel storage tanks. Each generator is capable of generating approximately 2.5 megawatts of power. These generators are necessary because of the high cost of electricity. The operation of the generators will not occur beyond 2 years and is not expected to last for an extended period of time, but rather only for the length of time necessary for Cenex to acquire a more economical supply of power.

Because these generators would only be used when commercial power is too expensive to obtain, the amount of emissions expected during the actual operation of these generators is minor. In addition, the installation of these generators qualifies as a “temporary source” under the PSD permitting program because the permit will limit the operation of these generators to a time period of less than 2 years. Therefore, Cenex would not need to comply with ARM 17.8.804, 17.8.820, 17.8.822, and 17.8.824. Even though the portable generators are considered temporary, the Department required compliance with best available control technology and public notice requirements; therefore, compliance with ARM 17.8.819 and 17.8.826 would be ensured. In addition, Cenex would be responsible for complying with all applicable air quality standards. In order to keep this permitting action below the threshold of nonattainment area permitting requirements, Cenex requested a limitation to keep the project’s potential emissions of SO_2 below 40 tons. Permit #1821-06 replaced Permit #1821-05.

Permit #1821-07 was issued on August 28, 2001, to change the wording in Section VII.A.2, regarding the stack height on the temporary generators, to allow for the installation of mufflers on those stacks, thus increasing the total stack height. In addition, the Department modified the permit to eliminate references to the repealed odor rule (ARM 17.8.315), to correct conditions improperly referencing the incinerator rule (ARM 17.8.316), and to update a testing frequency on the product loading rack VCU based on the Title V permit term. Permit #1821-07 replaced Permit #1821-06.

On June 3, 2002, the Department received a request from Cenex to modify Permit #1821-07 to remove all references to 8 temporary, portable electricity generators. The generators were permitted under Permit #1821-06, with further clarification added in Permit #1821-07 regarding generator stack height. The generators have not been operated since August 10, 2001, and Cenex has no intention of operating them in the future. The references to the generators were removed, and the generators are no longer included in Cenex's permitted equipment. **Permit #1821-08** replaced Permit #1821-07.

On March 13, 2003, the Department received a complete Montana Air Quality Permit Application from Cenex to modify Permit #1821-08 to add a new Ultra Low Sulfur Diesel (ULSD) Unit, Hydrogen Plant, and associated equipment to meet the EPA's 15 parts per million (ppm) sulfur standard for highway diesel fuel for 2006. The permit action removed the Middle Distillate Unifiner (MDU) charge heater, MDU stripper heater, MDU fugitives, and the #3 and #4 Unifier Compressors. The ULSD Unit included two heaters, four compressors, C-901 A/B and C-902 A/B, process drains, and fugitive piping components. The Hydrogen Plant included a single fired reformer heater, process drains, and fugitive piping components. The treated stream from the ULSD Unit were separated into its constituent fuel blending products or into material needing further refining. The resulting stream was then stored in existing tanks and one new tank (128). Three existing tanks (73, 86, and 117) were converted to natural gas blanketed tanks to reduce emissions of volatile organic compounds (VOCs) from the ULSD Unit feed stock product streams. Cenex was to install a new TGTU for both the SRU #1 and #2 trains that will be operational prior to startup of the ULSD Unit but technically are not part of this permitting action. **Permit #1821-09** replaced Permit #1821-08.

C. Current Permit Action

On July 30, 2003, the Department received a complete Montana Air Quality Permit Application from CHS Inc. to modify Permit #1821-09. The application was complete with the addition of modeling information provided to the Department on August 22, 2003. CHS Inc. requested to add a new TGTU and associated equipment for Zone A's SRU #1 and SRU #2 trains to control and reduce SO_2 emissions from this source. CHS Inc. submitted modeling to the Department for a determination of a minimum stack height for the existing SRU #1 and SRU #2 tail gas incinerator stack. CHS Inc. also submitted a letter to the Department to change the name on the permit from Cenex to CHS Inc. The current permit action adds the new TGTU, sets a minimum stack height for the tail gas incinerator stack, and changes the name on the permit from Cenex to CHS Inc. **Permit #1821-10** replaces Permit #1821-09.

D. Process Description

HDS Complex - CHS Inc. has constructed a new desulfurization complex within the existing refinery to desulfurize the gas-oil streams from the crude, vacuum, and the propane deasphalting units. The HDS unit removes sulfur from the gas-oil feedstock before further processing by the existing FCC unit. The new HDS unit greatly reduces the sulfur content of the FCCU feeds and, thereby, reduces the regenerator sulfur oxide emissions. Sulfur oxide emissions from the FCCU occur when coke-sulfur is burned off the catalyst at the unit's regenerator. Also, the FCCU clarified oil will contain a much lower sulfur content due to the HDS unit. FCCU clarified oil, when burned throughout the refinery in various furnaces and boilers, will result in lower sulfur oxide emissions. By removing sulfur compounds from the gas-oil and other FCCU feedstocks, the HDS process effectively reduces the sulfur content of refinery finished products, such as gasoline, kerosene, and diesel fuel. Lower sulfur content in gasoline and diesel fuels results in lower sulfur oxide emissions to the atmosphere from combustion by motor vehicle engines. Additionally, the desulfurization project includes other new process units, such as the SWS, amine, SRU, and the TGTU. The new Hydrogen Plant and new HDS unit make up the new desulfurization complex for the refinery. Flow diagrams for the FCC feed desulfurizer complex and proposed refinery flow scheme were submitted as part of the HDS complex permit application.

CHS Inc. filed a petition for declaratory judgement, which was granted by district court, which affords confidentiality protection on all HDS process and material rates, unit and equipment capacities, and other information relating to production. These are declared to be trade secrets and are not part of the public record. Hence, the reason for not providing the barrels-per-stream-day (BPSD) capacity of the new HDS unit and other new units, save the SRU, considered in this permit application analysis.

Hydrogen Plant - This unit produces pure hydrogen from propane/natural gas and recycled hydrocarbon from the hydrodesulfurizer, which, in turn, is used in the HDS unit. The feed is first purified of sulfur and halide compounds by conversion over a cobalt/molybdenum catalyst and subsequent absorption removal. The purified hydrocarbon is mixed with steam and the whole stream is reformed over a nickel catalyst to produce hydrogen (H_2), CO, carbon dioxide (CO_2), and methane (CH_4). The CO is converted to CO_2 over an iron oxide catalyst and the total gas stream cooled and finally purified by a solid absorbent in a fixed bed or Pressure Swing Adsorption unit (PSA), (hydrogen purification unit).

The reformer heater (H-101) is utilized by the Hydrogen Plant. The design heat input rate is 123.2 MMBtu/hr; however, CHS Inc. has determined that heat inputs of up to 135.5 MMBtu/hr are necessary for short periods of time. This heater burns a combination of natural/refinery gas and recovered PSA gas. PSA gas (374Mscf/hr) supplies 85% (104.7 MMBtu/hr) of the necessary fuel requirement. The remaining 15% (18.5 MMBtu/hr) fuel requirement is supplied by natural/refinery gas (19.3Mscf/hr).

HDS Unit – A feed blend of preheated gas oils/light cycle oils from various crude units are filtered and dewatered. The feed is further heated by the reactor charge heater (H-201) and combined with a stream of hydrogen-rich treat gas and charged to the first of three possible reactors. Only two reactors (first and second) are being installed and a third reactor may be added in the future. The reactors contain one or more proprietary hydro-treating catalysts, which convert combined sulfur and nitrogen in the feed into hydrogen sulfide (H_2S) and ammonia (NH_3). Effluent off the reactor flows to a hot high-pressure separator where the vapor and liquid phases separate. The vapor/liquid stream then enters the cold high-pressure separator where the phases separate. Liquid water separates from the liquid hydrocarbon phase and collects in the boot of the vessel where vapor separates from the liquids. The vapor stream from the cold high-pressure separator flows to the high-pressure absorber, where it is contacted with amine solution to remove H_2S. The vapor stream is then subjected to a water wash to remove entrained amine.

Amine, rich in H_2S, is pressured from the bottom of the absorber to the amine regeneration unit. The scrubbed and washed gas leaves the top of the high-pressure absorber and passes to the recycle cylinders of the make-up/recycle gas compressors. A portion of the discharge gas from these compressor cylinders is used as quench to control the inlet temperatures of the second reactor (and possibly a third reactor in the future).

H_2 from the Hydrogen Plant flows into the make-up/recycle gas unit section. The H_2 is compressed in the two-stage make-up cylinders of the make-up/recycle gas compressors and then mixed with the recycle gas stream. The combined gas (treat gas) recovers heat from the hot high-pressure separator and is then injected into the preheated oil feed at the inlet of the heat recovery exchangers.

In the fractionation section of the HDS unit, hot liquid from the hot high-pressure separator is mixed with cold liquid from the cold high-pressure separator and the combined stream is flashed into the H_2S stripper tower. The heat in the tower feed and steam stripping separates an off-gas product from the feed with essentially complete removal of H_2S from the bottom product. This off-gas product leaves the H_2S stripper overhead drum and flows to the amine unit for recovery of sulfur. The bottom product from the H_2S stripper is heated in the fractionator feed heater (H-202) and is charged to the flash zone of the fractionator. In the fractionator tower and associated diesel stripper tower, H_2S stripper bottoms are separated into a naphtha overhead product, a diesel stripper stream product, and a bottom product of FCC feed. Separation is achieved by heat in the feed, steam stripping of the bottom product, and reboiling of the diesel product.

The naphtha product is pumped from the fractionator overhead drum to intermediate storage. The diesel and bottoms desulfurized gas-oil (FCC feed) products are also pumped to intermediate storage. A new wash water and sour water system will accompany the reaction/separation section of the HDS unit. Water is pumped from the wash water surge tank and injected into the inlet of the high-pressure separator vapor condenser to remove salts and into the high-pressure absorber circulating water system to remove amine. Water injected to the hot high-pressure separator vapor condenser produces sour water, which accumulates in the water boot of the cold/high-pressure separator. This sour water is pressured to the sour water flash drum. Additional sour water is produced from stripping steam and heater injection steam and accumulates in the water boots of the H_2S stripper overhead drum and the fractionator overhead drum. Other accumulations from sour water sources, such as knock-out drums, are also sent up to the sour water flash drum. The sour water is pressured from the sour water flash drum and sent to the sour water storage tank.

A reactor charge heater (H-201) and fractionator feed heater (H-202) is utilized by the HDS unit. H-201 design heat input rate is 37.7 MMBtu/hr. Once the HDS reactors are at operating temperature, the process is exothermic. As a result, H-201 firing rates are reduced. For purposes of this application, the worst case assumption is made that H-201 always operates at 80% for design (30.2 MMBtu/hr and 31.2 Mscf/hr). H-202 heat input design rate is 27.2 MMBtu/hr. Similar to H-201, once the HDS reactors are at operating temperature, the process is exothermic and produces sufficient heat to sustain the reaction temperature. Excess heat is recovered and transferred to the fractionator feed which reduces the need for the fractionator feed heater. For purposes of this application, the worst case assumption is made that H-202 operates at 75% of full design capacity (20.4 MMBtu/hr and 21.3 Mscf/hr).

The new natural gas-fired compressor engine (C-201B) is utilized by the make-up/recycle gas section of the HDS unit. Two combined compressors operate in parallel at 50% of design duty or at 2/3 of machine design capacity. Each compressor is designed for 75% of the design process duty. The gas-fired engine is a 2000-HP (horsepower) rated unit. For purposes of the application, pollutant emission rates are based on normal operating load of 1060 HP (7918 scf/hr). The compressor engine will not fire refinery fuel gas; instead, natural gas will be burned with propane as a contingency fuel.

Amine Unit - A solution of amine (nitrogen-containing organic compounds) in water removes H_2S from two refinery gas streams. The new amine unit will not process sour refinery fuel gas since this operation is to be handled by the existing refinery amine unit, except for amine unit start-up operations.

Amine temperature is controlled to assure that no hydrocarbon condensation occurs in the absorber tower. A large flash tank with a charcoal filter is used to remove any dissolved hydrocarbons. The flash vapor flows to the TGTU for sulfur recovery. Also from the flash tank, the rich amine flows through the rich/lean exchanger where it is heated and sent to the still regenerator. The regenerator is heat controlled. The clean amine level is controlled and the amine cooler stream is sent to a surge tank with a gas blanket. Lean low-pressure and high-pressure streams are pumped from the surge tank to their respective contactors. H_2S in the overhead gas from the amine still accumulator are directed to the new SRU.

Sour Water Stripper - A new SWS was constructed, which replaced the operation of the older existing SWS. The new SWS unit serves the existing and proposed facilities of this HDS project. The old SWS cannot be removed, however, and functions only as the back-up unit. Sour water from a variety of sources in the refinery is accumulated in the sour water storage tank where hydrocarbons are separated. The hydrocarbon is sent to the existing slop oil system for recovery. The gas vapors from the sour water tank are compressed and sent to the tail gas unit for sulfur recovery. Sour water from the storage tank is pumped into the SWS tower. Steam heat is applied to the stripper to remove H_2S and NH_3 from the water. The stripper overhead gas containing H_2S and NH_3 is sent to the new SRU for sulfur recovery and incineration of NH_3.

Sulfur Recovery Plant - The SRU is designed as a dual operation facility. The SRU has two different modes of operation.

Mode I - Standard Straight Through Operation is where the unit operates as a standard three-bed Claus unit. The Claus operation consists of a sulfur reaction furnace designed to sufficiently burn (oxidize) incoming acid gas (H_2S) to SO_2, to form water vapor and elemental sulfur. SO_2 further reacts with H_2S to form more sulfur and water vapor. This is accomplished over three sulfur reactor catalyst beds and four condensers. Following the final reactor and condensing phase, the tail gas from the SRU is directed to the TGTU where additional sulfur treating occurs to further enhance recovery.

The new SRU has a design input rate of 79.18 short tons of sulfur per day (70.69 long ton/day) from three refinery feed streams. The overall efficiency of Mode I operation is 97.0%. This figure does not include additional sulfur recovery at the TGTU.

Mode II - Sub-Dew Point Operation utilizes the same Claus reaction and front-end operation, except the second and third catalyst beds are alternated as sub-dew point reactors. The gas flow is switched between the two beds. When a bed is in the last position, the inlet temperature is lowered, which allows further completion of the H_2S-

SO_2 reaction and, thereby, recovering more sulfur. The sulfur produced condenses, due to the lower temperature, and is absorbed by the catalyst. After 24 hours of absorbing sulfur, the switching valve directs the gas flow from the third reactor to the second reactor and from reactor #2 to reactor #3. The cold bed is then heated by being diverted to the hot position and all the absorbed sulfur is vaporized off, condensed and collected. The former hot bed is then cooled and utilized as the sub-dew point reactor for a period of 24 hours. The system cycles on a daily basis. The overall efficiency of Mode II operation is 98.24%. This figure does not include additional sulfur recovery at the TGTU. The advantage to two different modes of operation is for those times when the TGTU is not operating. The final heater (E-407) is used during the standard Claus unit operation; but, during the sub-dew point mode, it is blocked to prevent sulfur accumulation.

Tail Gas Treating Unit - The TGTU converts all sulfur compounds to H_2S so they can be removed and recycled back to the SRU for reprocessing. This process is accomplished by catalytically hydrogenating the Claus unit effluent in a reactor bed. From the reactor, the vapor is cooled in a quench tower before entering the unit's amine contactor. The hot vapors enter the bottom of the quench tower and contact water coming down the tower. The water is sent through a cooler exchanger and recycled in the tower. Excess water is drawn off and sent to the new sour water storage system. The cooled-off gas enters the bottom of the unit's amine contactor where H_2S is removed prior to final incineration. The TGTU's amine contactor and regeneration system are separate from the other two amine units previously mentioned. This design prevents cross-contamination of amine solutions. The off-gas from the TGTU amine contactor containing residual H_2S is sent to the sulfur plant incinerator. The concentrated H_2S stream is directed to the SRU sulfur reaction furnace, which converts the H_2S to SO_2, which recycles through the Claus process. The efficiency of the TGTU for sulfur removal is 99.46%. The TGTU adds additional sulfur recovery efficiency to the sulfur plant. The overall efficiency for sulfur removal for the SRU, plus TGTU, is 99.96%.

The sulfur plant incinerator (INC-401) is designed to burn any H_2S and other substances that make it past the SRU and TGTU. Also, exhaust gas from reheater E-407 (operated during Mode I) at the SRU is vented to the sulfur plant incinerator. The design heat input rate for reheater E-407 is 1.0 MMBtu/hr and is fired by natural/refinery gas. The design heat input rate for INC-401 is 3.8 MMBtu/hr. Therefore, these two fuel-burning devices, together, will fire a potential 5.0 Mscf/hr of fuel gas (4.8 total MMBtu/hr).

The overhead gas (H_2S, NH_3) from the SWS unit is treated by the SRU. SWS gas from the existing unit is currently incinerated at the FCC-CO boiler and results in significant emissions of SO_2 and NO_x. This refinery activity and resultant emissions will cease, contemporaneously, with the new HDS operation. Also, the sulfur feed to the existing refinery Claus SRU will be greatly diminished. This should result in significant SO_2 emission reductions, which have not been quantified.

Ultra Low Sulfur Diesel Unit and Hydrogen Plant – The ULSD Unit is designed to process approximately 21,000 bpd to meet the new sulfur standards for highway diesel fuel as mandated through the national sulfur control program in 40 CFR Parts 69, 80, and 86. CHS Inc. will shut down the existing MDU and replace it with the ULSD Unit to produce ultra low sulfur diesel and other fuels. The ULSD Unit will use the existing MDU process feeds including; raw diesel from #1 and #2 Crude Units, hydrotreated diesel from the Gas Oil Hydrotreater, light cycle oil from the FCCU, and burner fuel from the #1 and #2 Crude Units. The feed streams will be processed into several product streams; finished diesel, finished #1 burner fuel, and raw naphtha. These products will be stored in existing tanks dedicated to similar products from the MDU. Seven storage tanks will be modified as a result of the ULSD Unit project.

CHS Inc.'s existing Hydrogen Plant and the proposed Hydrogen Plant will supply hydrogen for hydrotreatment. These units catalytically reform a heated propane/natural gas and steam mixture into hydrogen and carbon dioxide then purify the hydrogen steam for use in the ULSD Unit. Existing plant sources will also supply steam and amine for the ULSD Unit.

Sour water produced in the ULSD Unit will be managed by existing equipment, including a sour water storage tank and a sour water stripper that vents to SRU #400. Fuel gas produced in the unit will be treated and distributed within the plant fuel gas system. Oily process wastewater and storm water from process areas managed in existing systems will be treated in the existing plant wastewater treatment plant.

Zone A's TGTU for SRU #1 and #2 Trains - The SRUs convert H_2S from various units within the refinery into molten elemental sulfur. The SRU process consists of two parallel trains (SRU #1 and SRU #2 trains) that each include thermal and catalytic sections that convert the H_2S and SO_2 into sulfur. In each train, the process gas exits the catalytic reactors and enters a condenser where sulfur is recovered and is gravity fed into the sulfur pits. Process gas from the condensers is then sent to the TGTU for additional sulfur removal. The TGTU is an amine-type H_2S recovery and recycle TGTU. The TGTU utilizes an in-line tail gas heater (TGTU-AUX-1), which also generates hydrogen from reducing gases that reduce the SO_2 in the tail gas to H_2S. After passing through the quench tower, the stream enters an amine absorber where H_2S is selectively absorbed. The off-gas passes to the SRU-AUX-4, where it is incinerated to convert remaining H_2S to SO_2 before venting to atmosphere. The rich amine leaving the absorber is regenerated in the tail gas regenerator, and the H_2S recovered is routed back to the front of the SRU unit. The lean amine is routed to a new MDEA surge tank (TGTU-VSSL-6). The efficiency of the TGTU for sulfur removal is 98.93%. The TGTU adds additional sulfur recovery efficiency to the sulfur plant. The overall efficiency for sulfur removal for the SRU, plus TGTU, plus the SRU-AUX-4, is nearly 100%.

The SRU-AUX-4 is designed to burn any H_2S and other substances that make it past the SRU and TGTU. Also, exhaust gas from the SRU-AUX-1 is vented to SRU-AUX-4. The design heat input rate for TGTU-AUX-1 is 4.17 MMBtu/hr and the unit is fired by natural/refinery fuel gas. The design heat input rate for SRU-AUX-4 is 10.85 MMBtu/hr and the unit is fired on refinery fuel gas. Therefore, these two fuel-burning devices, together, will potentially use 18.55 Mscf/hr of natural and refinery fuel gas (15.02 total MMBtu/hr).

E. Additional Information

Additional information, such as applicable rules and regulations, BACT determinations, air quality impacts, and environmental assessments, is included in the analysis associated with each change to the permit.

II. Applicable Rules and Regulations

The following are partial explanations of some applicable rules and regulations that apply to the facility. The complete rules are stated in the ARM and are available upon request from the Department. Upon request, the Department will provide references for locations of complete copies of all applicable rules and regulations, or copies, where appropriate.

A. ARM 17.8, Subchapter 1 – General Provisions, including, but not limited to:

1. ARM 17.8.101 Definitions. This rule is a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.105 Testing Requirements. Any person or persons responsible for the emission of any air contaminant into the outdoor atmosphere shall, upon written request of the Department, provide the facilities and necessary equipment, including instruments and sensing devices, and shall conduct tests, emission or ambient, for such periods of time as may be necessary, using methods approved by the Department.

3. ARM 17.8.106 Source Testing Protocol. The requirements of this rule apply to any emission source testing conducted by the Department, any source, or other entity as required by any rule in this chapter, or any permit or order issued pursuant to this chapter, or the provisions of the Montana Clean Air Act, 75-2-101, *et seq*., Montana Code Annotated (MCA).

   CHS Inc. shall comply with all requirements contained in the Montana Source Test Protocol and Procedures Manual including, but not limited to, using the proper test methods and supplying the required reports. A copy of the Montana Source Test Protocol and Procedures Manual is available from the Department upon request.

4. ARM 17.8.110 Malfunctions. The Department must be notified promptly by telephone whenever a malfunction occurs that can be expected to create emissions in excess of any applicable emission limitation, or to continue for a period greater than 4 hours.

5. ARM 17.8.111 Circumvention. No person shall cause or permit the installation or use of any device or any means which, without resulting in reduction in the total amount of air contaminant emitted, conceals or dilutes an emission of air contaminant which would otherwise violate an air pollution control regulation. No equipment that may produce emissions shall be operated or maintained in such a manner that a public nuisance is created.

B. ARM 17.8, Subchapter 2 – Ambient Air Quality, including, but not limited to:

1. ARM 17.8.204 Ambient Air Monitoring
2. ARM 17.8.210 Ambient Air Quality Standards for Sulfur Dioxide
3. ARM 17.8.211 Ambient Air Quality Standards for Nitrogen Dioxide
4. ARM 17.8.212 Ambient Air Quality Standards for Carbon Monoxide
5. ARM 17.8.213 Ambient Air Quality Standard for Ozone
6. ARM 17.8.214 Ambient Air Quality Standard for Hydrogen Sulfide
7. ARM 17.8.221 Ambient Air Quality Standard for Visibility
8. ARM 17.8.223 Ambient Air Quality Standard for PM_{10}

CHS Inc. must comply with the applicable ambient air quality standards.

C. ARM 17.8, Subchapter 3 – Emission Standards, including, but not limited to:

1. <u>ARM 17.8.304 Visible Air Contaminants</u>. This rule requires that no person may cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes.
2. <u>ARM 17.8.322 Sulfur Oxide Emissions -- Sulfur in Fuel</u>. Commencing July 1, 1971, no person shall burn any gaseous fuel containing sulfur compounds in excess of 50 grains per 100 cubic feet of gaseous fuel, calculated as hydrogen sulfide at standard conditions.

3. <u>ARM 17.8.340 Standard of Performance for New Stationary Sources</u>. The owner or operator of any stationary source or modification, as defined and applied in 40 CFR Part 60, shall comply with the standards and provisions of 40 CFR Part 60, Standards of Performance for New Stationary Sources (NSPS). The applicable NSPS Subparts include, but are not limited to:

   a. Subpart A - General Provisions apply to all equipment or facilities subject to an NSPS Subpart as listed below.

   b. Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units applies to the #10 Boiler.

   c. Subpart J - Standards of Performance for Petroleum Refineries shall apply to the SRU Incinerator Stack (E-407 & INC-401), Fractionator Feed Heater Stack (H-202), Reactor Charge Heater Stack (H-201), the Reformer Heater Stack (H-101), the two ULSD Unit heaters (H-901 and H-902), the Hydrogen Plant heater (H-801), Zone A SRU Incinerator Stack (SRU-AUX-4), and any other applicable equipment at the Laurel refinery. This subpart will also apply to the #10 Boiler as of November 1, 1997.

   d. Subpart GGG - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries shall apply to the HDS Complex, including, but not be limited to, the SRU Incinerator Stack (E-407 & INC-401), Superior Clean Burn II 12 SGIB (C201-B), Fractionator Feed Heater Stack (H-202), Reactor Charge Heater Stack (H-201), the Reformer Heater Stack (H-101), refinery fuel gas supply lines to the #10 Boiler, the fugitive ULSD Unit and Hydrogen Plant fugitive piping equipment, the Zone A TGTU fugitive piping equipment in VOC service, and any other applicable equipment constructed or modified after January 4, 1983.

   e. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refining Wastewater Systems shall apply to the HDS Complex, but not be limited to, SRU Incinerator Stack (E-407 & INC-401), Superior Clean Burn II 12 SGIB (C201-B), Fractionator Feed Heater Stack (H-202), Reactor Charge Heater Stack (H-201), the Reformer Heater Stack (H-101), the ULSD Unit and Hydrogen Plant wastewater streams, the Zone A TGTU process drains, and any other applicable equipment. NSPS Subpart QQQ does not apply to boiler #10, since the boiler drains will not contain any oily wastewater.

4. ARM 17.8.342 Emission Standards for Hazardous Air Pollutants for Source Categories. The source, as defined and applied in 40 CFR Part 63, shall comply with the requirements of 40 CFR Part 63, as listed below:

   a. Subpart A - General Provisions applies to all NESHAP source categories subject to a Subpart as listed below.

   b. Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries shall apply to, but not be limited to, the Product Loading Rack and tank 96 when it is brought into gasoline service.

   c. Subpart UUU – MACT Standard for Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units.

   d. Subpart DDDDD – Industrial Boilers and Process Heaters shall apply to, (as applicable after promulgation), but not limited to, the Reactor Charge Heater (H-901), the Fractionation Heater (H-902), and the H_2 Reformer Heater (H-801).

D. ARM 17.8, Subchapter 4 – Stack Height and Dispersion Techniques, including but not limited to:

   1. ARM 17.8.401 Definitions. This rule includes a list of definitions used in this chapter, unless indicated otherwise in a specific subchapter.

   2. ARM 17.8.402 Requirements. CHS Inc. must demonstrate compliance with the ambient air quality standards with a stack height that does not exceed Good Engineering Practices (GEP).

E. ARM 17.8, Subchapter 5 – Air Quality Permit Application, Operation and Open Burning Fees, including, but not limited to:

   1. ARM 17.8.504 Air Quality Permit Application Fees. This rule requires that an applicant submit an air quality permit application fee concurrent with the submittal of an air quality permit application. A permit application is incomplete until the proper application fee is paid to the Department. CHS Inc. submitted the appropriate permit application fee for the current permit action.

   2. ARM 17.8.505 Air Quality Operation Fees. An annual air quality operation fee must, as a condition of continued operation, be submitted to the Department by each source of air contaminants holding an air quality permit, excluding an open burning permit, issued by the Department; and the air quality operation fee is based on the actual or estimated actual amount of air pollutants emitted during the previous calendar year.

      The annual assessment and collection of the air quality operation fee, described above, shall take place on a calendar-year basis. The Department may insert into any final permit issued after the effective date of these rules, such conditions as may be necessary to require the payment of an air quality operation fee on a calendar-year basis, including provisions which prorate the required fee amount.

F. ARM 17.8, Subchapter 7 – Permit, Construction, and Operation of Air Contaminant Sources, including, but not limited to:

1. ARM 17.8.740 Definitions. This rule is a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.743 Montana Air Quality Permits--When Required. This rule requires a person to obtain an air quality permit or permit alteration to construct, alter or use any air contaminant sources that have the Potential to Emit (PTE) greater than 25 tons per year of any pollutant. CHS Inc. has the potential to emit more than 25 tons per year of SO_2, NO_x, CO, VOC, and PM emissions; therefore, an air quality permit is required.

3. ARM 17.8.744 Montana Air Quality Permits--General Exclusions. This rule identifies the activities that are not subject to the Montana Air Quality Permit program.

4. ARM 17.8.745 Montana Air Quality Permits—Exclusion for De Minimis Changes. This rule identifies the de minimis changes at permitted facilities that do not require a permit under Montana Air Quality Permit Program.

5. ARM 17.8.748 New or Modified Emitting Units--Permit Application Requirements. (1) This rule requires that a permit application be submitted prior to installation, alteration or use of a source. CHS Inc. submitted the required permit application for the current permit action. (7) This rule requires that the applicant notify the public by means of legal publication in a newspaper of general circulation in the area affected by the application for a permit. CHS Inc. submitted an affidavit of publication of public notice for the July 30, 2003, issue of the *Billings Gazette*, a newspaper of general circulation in the town of Billings in Yellowstone County, as proof of compliance with the public notice requirements.

6. ARM 17.8.749 Conditions for Issuance or Denial of Permit. This rule requires that the permits issued by the Department must authorize the construction and operation of the facility or emitting unit subject to the conditions in the permit and the requirements of this subchapter. This rule also requires that the permit must contain any conditions necessary to assure compliance with the Federal Clean Air Act (FCAA), the Clean Air Act of Montana, and rules adopted under those acts.

7. ARM 17.8.752 Emission Control Requirements. This rule requires a source to install the maximum air pollution control capability that is technically practicable and economically feasible, except that BACT shall be utilized. The required BACT analysis is included in Section III of this permit analysis.

8. ARM 17.8.755 Inspection of Permit. This rule requires that air quality permits shall be made available for inspection by the Department at the location of the source.

9. ARM 17.8.756 Compliance with Other Requirements. This rule states that nothing in the permit shall be construed as relieving CHS Inc. of the responsibility for complying with any applicable federal or Montana statute, rule, or standard, except as specifically provided in ARM 17.8.740, *et seq*.

10. ARM 17.8.759 Review of Permit Applications. This rule describes the Department's responsibilities for processing permit applications and making permit decisions on those permit applications that do not require the preparation of an environmental impact statement.

11. ARM 17.8.762 Duration of Permit. An air quality permit shall be valid until revoked or modified, as provided in this subchapter, except that a permit issued prior to construction of a new or altered source may contain a condition providing that the permit will expire unless construction is commenced within the time specified in the permit, which in no event may be less than 1 year after the permit is issued.

12. ARM 17.8.763 Revocation of Permit. An air quality permit may be revoked upon written request of the permittee, or for violations of any requirement of the Clean Air Act of Montana, rules adopted under the Clean Air Act of Montana, the FCAA, rules adopted under the FCAA, or any applicable requirement contained in the Montana State Implementation Plan (SIP).

13. ARM 17.8.764 Administrative Amendment to Permit. An air quality permit may be amended for changes in any applicable rules and standards adopted by the Board of Environmental Review (Board) or changed conditions of operation at a source or stack that do not result in an increase of emissions as a result of those changed conditions. The owner or operator of a facility may not increase the facility's emissions beyond permit limits unless the increase meets the criteria in ARM 17.8.745 for a de minimis change not requiring a permit, or unless the owner or operator applies for and receives another permit in accordance with ARM 17.8.748, ARM 17.8.749, ARM 17.8.752, ARM 17.8.755, and ARM 17.8.756, and with all applicable requirements in ARM Title 17, Chapter 8, Subchapters 8, 9, and 10.

14. ARM 17.8.765 Transfer of Permit. This rule states that an air quality permit may be transferred from one person to another if written notice of Intent to Transfer, including the names of the transferor and the transferee, is sent to the Department.

G. ARM 17.8, Subchapter 8 – Prevention of Significant Deterioration of Air Quality, including, but not limited to:

1. ARM 17.8.801 Definitions. This rule is a list of applicable definitions used in this subchapter.

2. ARM 17.8.818 Review of Major Stationary Sources and Major Modifications -- Source Applicability and Exemptions. The requirements contained in ARM 17.8.819 through ARM 17.8.827 shall apply to any major stationary source and any major modification with respect to each pollutant subject to regulation under the FCAA that it would emit, except as this subchapter would otherwise allow. CHS Inc.'s existing petroleum refinery in Laurel is defined as a "major stationary source" because it is a listed source with the potential to emit more than 100 tons per year of several pollutants (PM, SO_2, NO_x, CO, and VOCs).

   This modification will not cause a net emission increase greater than significant levels and, therefore, does not require a New Source Review (NSR) analysis. The net emission changes are as follows:

Emission Source	Constituent	Average 2-yr Actuals (ton/yr)	Proposed PTE (ton/yr)	Net Emission Change (ton/yr)	PSD Significance Level (ton/yr)
Zone A TGTU Project Emissions Summary	SO_2	(1587.9)	20.3	(1567.6)	40
	NO_X	3.1	4.8	1.7	40
	PM_{10}	0.2	0.5	0.3	15
	PM	0.2	0.5	0.3	35
	VOC	0.1	4.6	4.5	40
	CO	2.6	10.9	8.3	100

H. ARM 17.8, Subchapter 9 – Permit Requirements for Major Stationary Sources of Modifications Located within Nonattainment Areas including, but not limited to:

ARM 17.8.904 When Air Quality Preconstruction Permit Required. This rule requires that major stationary sources or major modifications located within a nonattainment area must obtain a preconstruction permit in accordance with the requirements of this Subchapter, as well as the requirements of Subchapter 7.

The current permit action is not considered a major modification because the increase in emissions is less than significance levels. Therefore, the requirements of this subpart are not applicable.

I. ARM 17.8, Subchapter 12 – Operating Permit Program Applicability, including, but not limited to:

1. ARM 17.8.1201 Definitions. (23) Major Source under Section 7412 of the FCAA is defined as any stationary source having:

   a. PTE > 100 tons/year of any pollutant;

   b. PTE > 10 tons/year of any one Hazardous Air Pollutant (HAP), PTE > 25 tons/year of a combination of all HAPs, or a lesser quantity as the Department may establish by rule; or

   c. PTE > 70 tons/year of PM_{10} in a serious PM_{10} nonattainment area.

2. ARM 17.8.1204 Air Quality Operating Permit Program Applicability. (1) Title V of the FCAA Amendments of 1990 requires that all sources, as defined in ARM 17.8.1204 (1), obtain a Title V Operating Permit. In reviewing and issuing Air Quality Permit #1821-10 for CHS Inc., the following conclusions were made:

   a. The facility's PTE is greater than 100 tons/year for several pollutants.

   b. The facility's PTE is greater than 10 tons/year for any one HAP and greater than 25 tons/year of all HAPs.

   c. This source is not located in a serious PM_{10} nonattainment area.

   d. This facility is subject to NSPS requirements.

   e. This facility is subject to current NESHAP standards.

   f. This source is not a Title IV affected source, nor a solid waste combustion unit.

   g. This source is not an EPA designated Title V source.

Based on these facts, the Department determined that CHS Inc. is a major source of emissions as defined under Title V. CHS Inc.'s Title V Operating Permit was issued final on November 11, 2001. Further, the current permit action constitutes a significant modification to the existing Title V Operating Permit; therefore, in accordance with ARM 17.8.1227, CHS Inc. submitted a Title V permit application for this project concurrent with the Montana Air Quality permit application.

J. MCA 75-2-103, Definitions, provides, in part, as follows:

1. "Incinerator" means any single or multiple-chambered combustion device that burns combustible material, alone or with a supplemental fuel or catalytic combustion assistance, primarily for the purpose of removal, destruction, disposal, or volume reduction of all or any portion of the input material.

2. "Solid waste" means all putrescible and nonputrescible solid, semisolid, liquid, or gaseous wastes, including, but not limited to...air pollution control facilities...

K. MCA 75-2-215, Solid or Hazardous Waste Incineration -- Additional Permit Requirements, including, but not limited to, the following requirements:

The Department may not issue a permit to a facility until the Department has reached a determination that the projected emissions and ambient concentrations will constitute a negligible risk to the public health, safety, and welfare and to the environment.

CHS Inc. submitted a health risk assessment identifying the risk from the burning of HAPs in the flare as part of their permit application. The risk assessment contained the HAPs from the 1990 Federal Clean Air Act Amendments with an established risk value. The ambient concentrations were determined using ISCT3 and the risk assessment model used EPA's unit risk estimates and reference concentrations. The Department included limits in the permit that ensure the amount of material used in the models was not exceeded. The risk assessment results were summarized in the following table.

Flare Risk Assessment - CHS Inc. Refinery

	Hourly	Cancer	Non-Cancer	
	Conc	ELCR	Hazard Quotient	
Chemical Compound	µg/m3	Chronic	Chronic	Acute
Benzene*	4.67E-02	8.3E-06	3.9E-07	ND
Toluene	3.82E-02	ND	ND	ND
Ethyl Benzene	2.85E-03	ND	ND	ND
Xylenes	1.25E-02	ND	ND	ND
Hexane	8.55E-02	ND	ND	ND
Cumene	1.14E-04	ND	ND	ND
Napthalene	1.60E-05	ND	ND	ND
Biphenyl	7.98E-08	ND	ND	ND
Total Risks =	0.186	8.3E-06	3.9E-07	ND

*The reference concentration for Benzene is 71 µg/m^3 (EPA IRIS database).

The modeling demonstrated that the ambient concentrations of HAPs, with the exception of Benzene, are less than the concentrations contained in Table I and Table II of ARM 17.8.770; therefore, these HAPs were excluded from further review.

A risk assessment for Benzene was calculated because the predicted ambient concentration was greater than the concentration contained in Table I of ARM 17.8.770. This assessment demonstrated that the excess lifetime cancer risk was $3.9*10^{-7}$. Therefore, the Department determined that the health risk assessment model demonstrated negligible risk to public health in this case.

III. BACT Determination

A BACT determination is required for each new or altered source. CHS Inc. shall install on the new or altered source the maximum air pollution control capability that is technically practicable and economically feasible, except that BACT shall be utilized.

Because of the relatively small amount of NO_X, SO_X, PM_{10}, PM, VOC, and CO emissions produced by the TGTU project, add-on control for those pollutants would be cost prohibitive. Thus, the Department determined that no additional control would constitute BACT for NO_X, PM_{10}, PM, VOC, and CO. The control options selected have control and control costs similar to other recently permitted similar sources and are capable of achieving the appropriate emissions standards.

Although the TGTU project produces about 20.8 tons of SO_X per year, the net result after this project is a decrease of about 1,540 tons per year of SO_X.

IV. Emission Inventory

	Ton/yr					
Source	**PM**	**PM_{10}**	**NO_x**	**VOC**	**CO**	**SO_x**
Tail Gas Incinerator (SRU-AUX-4)	0.48	0.48	4.80	0.35	5.32	50.8
Tail Gas Heater (TGTU-AUX-1)				0.10	5.37	
MDEA Surge Tank (TGTU-VSSL-6)				0.00		
TGTU Fugitive Emissions				4.15		
Total	**0.48**	**0.48**	**4.80**	**4.60**	**10.69**	**50.8**

V. Existing Air Quality

The area (2.0 km) around the CHS Inc. Refinery in Laurel is federally designated as nonattainment for the SO_2 NAAQS (40 CFR 81.327). There are two areas in Billings (approximately 12 miles northeast of the CHS Inc. Refinery) which were federally designated nonattainment for CO (NAAQS) and for the old secondary total suspended particulates (PM) standard. The Billings CO nonattainment area was redesignated to attainment on April 22, 2002, by EPA. The old PM standard has since been revoked and replaced with new PM_{10} (respirable) standards. The Billings area is listed as not classified/attainment for the new PM_{10} standard. Ambient air quality monitoring data for SO_2 from 1981 through 1992 recorded SO_2 levels in the Laurel and Billings areas in excess of the Montana Ambient Air Quality Standards (MAAQS) for the 24-hour and annual averages. In 1993, EPA determined that the SO_2 SIP for the Billings/Laurel area was inadequate and needed to be revised. The Department, in cooperation with the Billings/Laurel area SO_2 emitting industries, adopted a new control plan to reduce SO_2 emissions by establishing emission limits and requiring continuous emission monitors on most stacks. Area SO_2 emissions have since declined between 1992 and 1999. The decline can be attributed to industrial controls added as part of the SIP requirements, plants operating at less than full capacity, and industrial process changes to meet sulfur in fuel regulations. Ambient air quality monitoring for SO_2, PM_{10}, and CO in the Billings/Laurel area continues.

VI. Air Quality Impacts

Comparison of Proposed Project Allowable Emissions to Current Actual Emissions:

Emission Source	Constituent	Average 2-yr Actuals Reduced	Proposed PTE (ton/yr)	Net Emission Change (ton/yr)	PSD Significance Level (ton/yr)

		(ton/yr)			
TGTU Unit Emissions Summary	SO_2	(1587.9)	20.3	(1567.6)	40
	NO_X	3.1	4.8	1.7	40
	PM_{10}	0.2	0.5	0.3	15
	PM	0.2	0.5	0.3	35
	VOC	0.1	4.6	4.5	40
	CO	2.6	10.9	8.3	100

The current permit action does not meet the threshold limits to require modeling for any pollutant. However, since Billings is classified as a nonattainment area for CO and Laurel is classified as a nonattainment area for SO_2, additional determinations need to be made for those two pollutants. The SIP for CO in Billings does not place any restrictions on any industrial source in the Billings area because only a very small percentage of CO emissions can be attributed to industrial activity. In addition, CHS Inc. is located 12 miles southwest of Billings, so the proposed emissions cap for CO will not adversely affect the Billings nonattainment area and no additional modeling will be required with respect to CO.

This permitting action does not request any deviation from the Laurel SO_2 SIP stipulations. Because the project results in a net reduction of SO_2 emissions and because the limits contained in the stipulations have been extensively modeled, no additional modeling will be required with respect to the SO_2 nonattainment area.

VII. Taking or Damaging Implication Analysis

As required by 2-10-101 through 105, MCA, the Department conducted a private property taking and damaging assessment and determined there are no taking or damaging implications.

VIII. Environmental Assessment

An environmental assessment, required by the Montana Environmental Policy Act, was completed for this project. A copy is attached.

DEPARTMENT OF ENVIRONMENTAL QUALITY
Permitting and Compliance Division
Air and Waste Management Bureau
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P.O. Box 200901, Helena, Montana 59620-0901
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FINAL ENVIRONMENTAL ASSESSMENT (EA)

Issued For: CHS Inc.
Laurel Refinery
P.O. Box 909
Laurel, MT 59044-0909

Permit Number: 1821-10

Preliminary Determination on Permit Issued: September 10, 2003
Department Decision Issued: September 30, 2003
Permit Final: October 16, 2003

1. Legal Description of Site: South ½, Section 16, Township 2 South, Range 24 East in Yellowstone County.

2. Description of Project: On July 30, 2003, the Department received Montana Air Quality Permit Application from CHS Inc. to modify Permit #1821-09 to change the name on the permit from Cenex Harvest States Cooperatives to CHS Inc. and to add a new TGTU and associated equipment. The application was complete with the addition of modeling information submitted by CHS Inc. on August 22, 2003.

3. Objectives of Project: CHS Inc. needs to meet the U.S. EPA's 15 parts per million (ppm) sulfur standard for highway diesel fuel beginning in 2006. CHS Inc. proposed to construct a new TGTU on Zone A's SRU #1 and SRU #2 trains as part of CHS Inc.'s effort comply with the new EPA standards.

4. Alternatives Considered: In addition to the proposed action, the Department also considered the "no-action" alternative. The "no-action" alternative would deny issuance of the Montana Air Quality permit to the proposed facility. However, the Department does not consider the "no-action" alternative to be appropriate because CHS Inc. demonstrated compliance with all applicable rules and regulations as required for permit issuance. Therefore, the "no-action" alternative was eliminated from further consideration.

5. A listing of mitigation, stipulations and other controls: A list of enforceable permit conditions and a complete permit analysis, including a BACT determination, would be contained in Permit #1821-10.

6. Regulatory effects on private property: The Department considered alternatives to the conditions imposed in this permit as part of the permit development. The Department determined that the permit conditions are reasonably necessary to ensure compliance with applicable requirements and to demonstrate compliance with those requirements and do not unduly restrict private property rights.

7. The following table summarizes the potential physical and biological effects of the proposed project on the human environment. The "no action alternative" was discussed previously.

		Major	Moderate	Minor	None	Unknown	Comments
A	Terrestrial and Aquatic Life and Habitats				X		Yes
B	Water Quality, Quantity and Distribution				X		Yes
C	Geology and Soil Quality, Stability and Moisture				X		Yes
D	Vegetation Cover, Quantity and Quality			X			Yes
E	Aesthetics			X			Yes
F	Air Quality			X			Yes
G	Unique Endangered, Fragile or Limited Environmental Resource				X		Yes
H	Demands on Environmental Resource of Water, Air and Energy			X			Yes
I	Historical and Archaeological Sites				X		Yes
J	Cumulative and Secondary Impacts			X			Yes

SUMMARY OF COMMENTS ON POTENTIAL PHYSICAL AND BIOLOGICAL EFFECTS: The following comments have been prepared by the Department.

A. Terrestrial and Aquatic Life and Habitats:

The addition of the TGTU would result in a significant decrease in SO_2 emissions from the project overall. The TGTU project results in slight increases of NO_X, CO, VOC, PM_{10}, and PM above historical emission levels. Impacts to terrestrial life and habitats may occur as a result of these increased emissions. Habitat impacts would not result in a change of diversity or abundance of terrestrial or aquatic life because the emissions from this project are minor. This area does not appear to contain any critical or unique wildlife habitat or aquatic life and the project would occur in an already disturbed area.

B. Water Quality, Quantity, and Distribution:

The actions addressed in this permit would not result in a change in the amount or characteristics of surface water discharged or the alteration of the course or magnitude of any drainage system. While deposition of pollutants would occur, the Department determined that any impacts from deposition of pollutants would be minor. Furthermore, this action would not result in a change in the quality or quantity of ground water. Therefore, no impacts to water quality, quantity, and/or distribution are anticipated. The proposed project would not change the water quality, water quantity, and distribution. There would be no discharges to groundwater or surface water from this project.

C. Geology and Soil Quality, Stability, and Moisture:

No additional disturbance would be created from this action. Existing structures and equipment would be removed to make room for the new equipment. While deposition of pollutants would occur, the Department determined that any impacts from deposition of pollutants would be minor. This project would not change the soil stability or geologic substructure or result in any increased disruption, displacement, erosion, compaction, or moisture loss, which would reduce productivity or fertility at or near the site. No unique geologic or physical features would be disturbed. Therefore, no impacts to geology and soil quality, stability, and moisture are anticipated. The issuance of the permit would not result in construction of any structures outside the area already disturbed; therefore, there would be no impact on the soil quantity, stability, moisture, or geology.

D. Vegetation Cover, Quantity, and Quality:

This project would be constructed on land already used for industrial activities. The vegetative cover, quantity, and quality would not be disturbed inside the facility boundaries. However, possible increases in actual emissions of NO_X, CO, VOC, PM_{10}, and PM from historical emission levels may result in minor impacts to the diversity, productivity, or abundance of plant species in the surrounding areas. The project alone produces a minor amount of SO_2 emissions but the net effect of the project is a significant decrease in SO_2 emissions. Issuance of this permit would cause minor if any changes in vegetation cover, its quantity, or its quality.

E. Aesthetics:

The proposed TGTU would be visible and would create additional noise in the area. However, the proposed facilities would be constructed in the area that has previously been disturbed and already has noise associated with its operation. Therefore, any additional impacts on aesthetics would be minor if any.

F. Air Quality:

No increase in allowable pollutant levels was included in the proposal. Actual levels of emissions of NO_X, CO, VOC, PM, and PM_{10} would increase slightly with the implementation of the TGTU project. However, the actual level of SO_2 emissions would decrease significantly with the implementation of TGTU project. Previously modeled levels of pollutants (at allowable levels) show compliance with the National Ambient Air Quality Standards (NAAQS) and the Montana Ambient Air Quality Standards (MAAQS). The overall impact on air quality is expected to be minor.

G. Unique Endangered, Fragile, or Limited Environmental Resources:

This permitting action may result in minor impacts to terrestrial and aquatic life and/or their habitat; therefore, it is possible that unique, rare, threatened, or endangered species may experience minor impacts. However, the Department is not aware of any unique, rare, threatened, or endangered species in the area surrounding the facility. Further, as described in Section 7.F. of this EA, pollutant emissions generated from the facility would have minimal impacts on air quality in the immediate and surrounding area because of the relatively small amount of pollution emitted. There would not be any additional impact to these resources because the project would occur at an already disturbed site.

H. Demands on Environmental Resource of Water, Air, and Energy:

This project would probably not consume any significant additional energy or water resources. Further, as described in Section 7.F. of this EA, pollutant emissions generated from the facility would have minimal impacts on air quality in the immediate and surrounding area because of the relatively small amount of pollution emitted. This action did not include an increase in allowable levels. Previous modeling efforts, using allowable levels, showed compliance with NAAQS and MAAQS. This project would result in a minor effect on the air resource, but resulting emissions will still comply with ambient air quality standards.

I. Historical and Archaeological Sites:

This project would not disturb a greater land surface than has already been occupied by the refinery. This project would occur within the boundaries of the area already disturbed. Therefore, no impacts to any historical and archaeological sites are anticipated.

J. Cumulative and Secondary Impacts:

Increases in actual pollutant emissions of NO_X, CO, VOC, PM_{10}, and PM from historical emission levels may result in minor cumulative and secondary impacts. The project alone produces a minor amount of SO_2 emissions but the net effect of the project is a significant decrease in SO_2 emissions. Minor cumulative or secondary impacts are expected to result from this project.

8. The following table summarizes the potential economic and social effects of the proposed project on the human environment. The "no action alternative" was discussed previously.

		Major	Moderate	Minor	None	Unknown	Comments
A	Social Structures and Mores				X		Yes
B	Cultural Uniqueness and Diversity				X		Yes
C	Local and State Tax Base and Tax Revenue			X			Yes
D	Agricultural or Industrial Production			X			Yes
E	Human Health			X			Yes
F	Access to and Quality of Recreational and Wilderness Activities				X		Yes
G	Quantity and Distribution of Employment				X		Yes
H	Distribution of Population				X		Yes
I	Demands for Government Services			X			Yes
J	Industrial and Commercial Activity				X		Yes
K	Locally Adopted Environmental Plans and Goals				X		Yes
L	Cumulative and Secondary Impacts			X			Yes

SUMMARY OF COMMENTS ON POTENTIAL ECONOMIC AND SOCIAL EFFECTS: The following comments have been prepared by the Department.

A. Social Structures and Mores:

The fundamental moral views of a social group are not anticipated to be altered as a result of this permitting action. The project would not have any impact on social structures or mores.

B. Cultural Uniqueness and Diversity:

The project would not alter the cultural uniqueness or diversity of the community surrounding the facility. No impact on cultural uniqueness or diversity would be associated with this project.

C. Local and State Tax Base and Tax Revenue:

This project would have a minor effect on the local and state tax base and tax revenue because this project would allow CHS Inc. to continue competitive operation of their facility.

D. Agricultural or Industrial Production:

This project would not result in a reduction of available acreage or productivity of any agricultural land; therefore, agricultural production should not be affected. Because of the location, along with the relatively small amount of pollution deposition, only minor affects to surrounding agricultural land would result. Minor impacts on agricultural and industrial production would result from this project because CHS Inc. would continue operation of their facility.

E. Human Health:

The two primary vehicles for impact upon human health are water and air. This permitting action would not result in a change in the amount or characteristics of surface water discharged or the quality or quantity of ground water. Therefore, human health impacts from water are not anticipated. The project includes relatively small increases in actual air pollutant emissions of NO_X, CO, VOC, PM_{10}, and PM from historical emission levels. The project alone produces a minor amount of SO_2 emissions but the net effect of the project is a significant decrease in SO_2 emissions from historical levels. Previous modeling efforts using allowable emission levels (which would not increase as a result of this action) showed compliance with air quality standards. These standards are designed to be protective of human health however; minor human health impacts from air quality are possible. Minimal health impacts for both water and air are anticipated.

F. Access to and Quality of Recreational and Wilderness Activities:

This project would not have an impact on recreational or wilderness activities because the construction site is far removed from recreational and wilderness areas or access routes. This project would not result in any changes in access to and quality of recreational and wilderness activities.

G. Quantity and Distribution of Employment:

This project would not result in any impacts to the quantity and distribution of employment at the facility or surrounding community because no new employees would be hired as a result this project.

H. Distribution of Population:

This project does not involve any significant physical or operational change that would affect the location, distribution, density, or growth rate of the human population. The distribution of population would not change as a result of this project.

I. Demands of Government Services:

Minor demands for government services would be expected. Additional time would potentially be spent on verifying the facility's compliance and issuing the necessary permits.

J. Industrial and Commercial Activity:

Industrial production and commercial activity at the facility or in the neighboring area is not anticipated to be altered by issuing Permit #1821-10.

K. Locally Adopted Environmental Plans and Goals:

This project would not affect any locally adopted environmental plans or goals CHS Inc. must continue to comply with the State Implementation Plan (SIP) and associated stipulations for the Billings/Laurel area. The Department is not aware of any locally adopted environmental plans and goals that would be impacted by this project.

L. Cumulative and Secondary Impacts:

Increases in actual pollutant emissions above historical levels may result in minor cumulative and secondary impacts to the human environment. Because of relatively small increases in actual air pollutant emissions of NO_X, CO, VOC, PM_{10}, and PM from historical emission levels minor cumulative or secondary impacts are expected to result from this project.

Recommendation: An EIS is not required.

If an EIS is not required, explain why the EA is an appropriate level of analysis: All potential effects resulting from construction and operation of the proposed facility would be minor; therefore, an EIS is not required. In addition, the source would be applying BACT and the analysis indicates compliance with all applicable air quality rules and regulations.

Other groups or agencies contacted or which may have overlapping jurisdiction: None.

Individuals or groups contributing to this EA: Department of Environmental Quality, Permitting and Compliance Division - Air and Waste Management Bureau.

EA prepared by: Chris Ames
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